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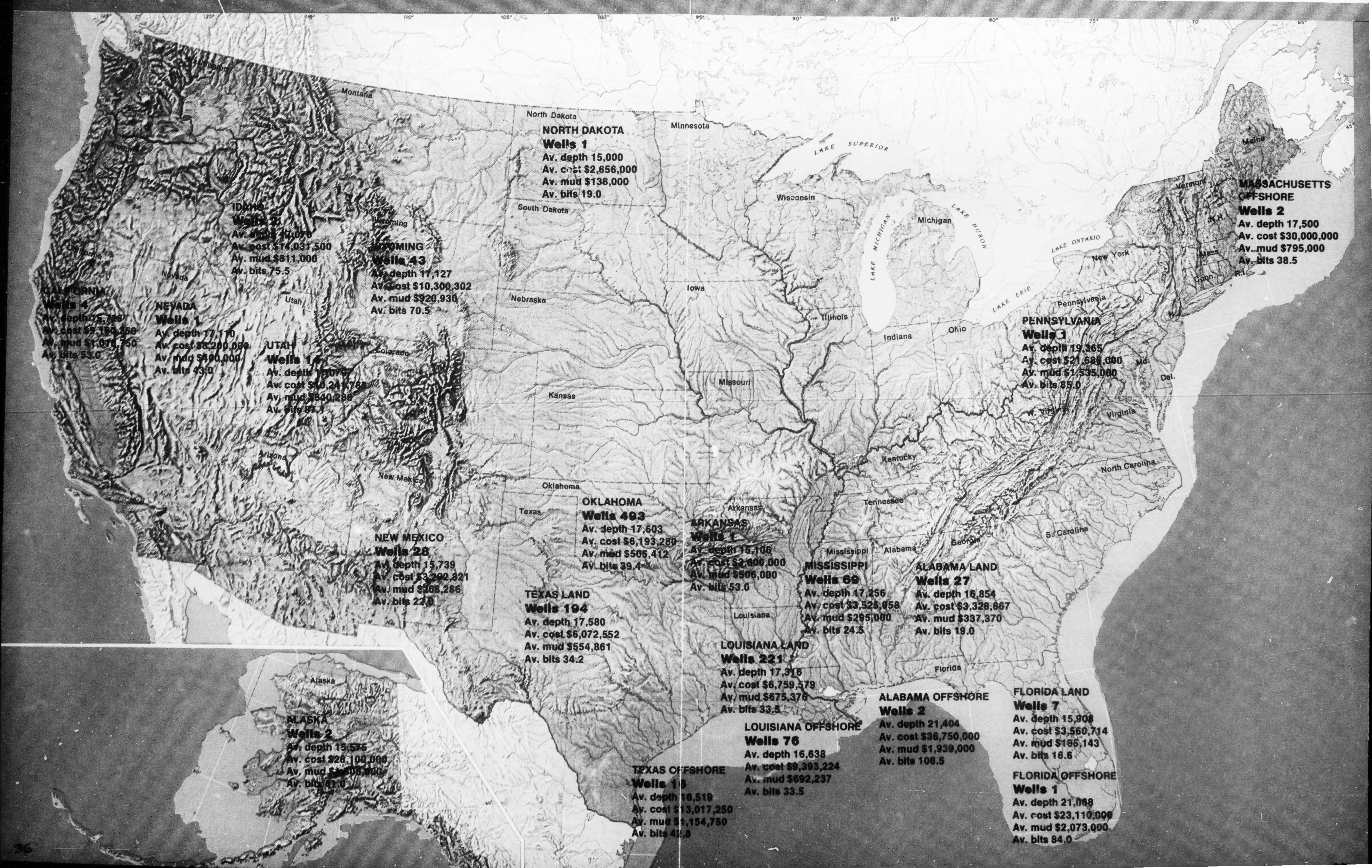
1982 U.S. deep drilling 1,205 deep wells


Montana
North Dakota
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Wisconsin
Michigan
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LAKE HURON
LAKE ONTARIO
LAKE ERIE
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Louisiana
Oklahoma
Texas
Kansas
Nebraska
South Dakota
Wyoming
Colorado
New Mexico
Arizona
Utah
Nevada
California
Oregon
Idaho
Washington
Alaska

NORTH DAKOTA
Wells 1
Av. depth 15,000
Av. cost $2,656,000
Av. mud $138,000
Av. bits 19.0

IDAHO
Wells 2
Av. depth 17,070
Av. cost $14,031,500
Av. mud $811,000
Av. bits 75.5

WYOMING
Wells 43
Av. depth 17,127
Av. cost $10,300,302
Av. mud $920,930
Av. bits 70.5

CALIFORNIA
Wells 4
Av. depth 15,725
Av. cost $9,160,250
Av. mud $1,010,750
Av. bits 53.0

NEVADA
Wells 1
Av. depth 17,110
Av. cost $8,200,000
Av. mud $400,000
Av. bits 43.0

UTAH
Wells 14
Av. depth 1[illegible],079
Av. cost $10,241,785
Av. mud $840,286
Av. bits 87.1

MASSACHUSETTS OFFSHORE
Wells 2
Av. depth 17,500
Av. cost $30,000,000
Av. mud $795,000
Av. bits 38.5

PENNSYLVANIA
Wells 1
Av. depth 19,365
Av. cost $21,686,000
Av. mud $1,535,000
Av. bits 85.0

OKLAHOMA
Wells 493
Av. depth 17,603
Av. cost $6,193,280
Av. mud $505,412
Av. bits 39.4

NEW MEXICO
Wells 28
Av. depth 15,739
Av. cost $3,292,821
Av. mud $268,286
Av. bits 22.0

ARKANSAS
Wells 1
Av. depth 15,106
Av. cost $3,600,000
Av. mud $506,000
Av. bits 53.0

MISSISSIPPI
Wells 69
Av. depth 17,256
Av. cost $3,525,058
Av. mud $295,000
Av. bits 24.5

ALABAMA LAND
Wells 27
Av. depth 16,854
Av. cost $3,328,667
Av. mud $337,370
Av. bits 19.0

TEXAS LAND
Wells 194
Av. depth 17,580
Av. cost $6,072,552
Av. mud $554,861
Av. bits 34.2

LOUISIANA LAND
Wells 221
Av. depth 17,316
Av. cost $6,759,579
Av. mud $675,376
Av. bits 33.5

ALABAMA OFFSHORE
Wells 2
Av. depth 21,404
Av. cost $36,750,000
Av. mud $1,939,000
Av. bits 106.5

FLORIDA LAND
Wells 7
Av. depth 15,908
Av. cost $3,560,714
Av. mud $185,143
Av. bits 16.6

ALASKA
Wells 2
Av. depth 15,575
Av. cost $28,100,000
Av. mud $1,500,000
Av. bits 61.0

LOUISIANA OFFSHORE
Wells 76
Av. depth 16,638
Av. cost $9,393,224
Av. mud $692,237
Av. bits 33.5

TEXAS OFFSHORE
Wells 16
Av. depth 16,519
Av. cost $13,017,250
Av. mud $1,154,750
Av. bits 42.8

FLORIDA OFFSHORE
Wells 1
Av. depth 21,068
Av. cost $23,110,000
Av. mud $2,073,000
Av. bits 84.0

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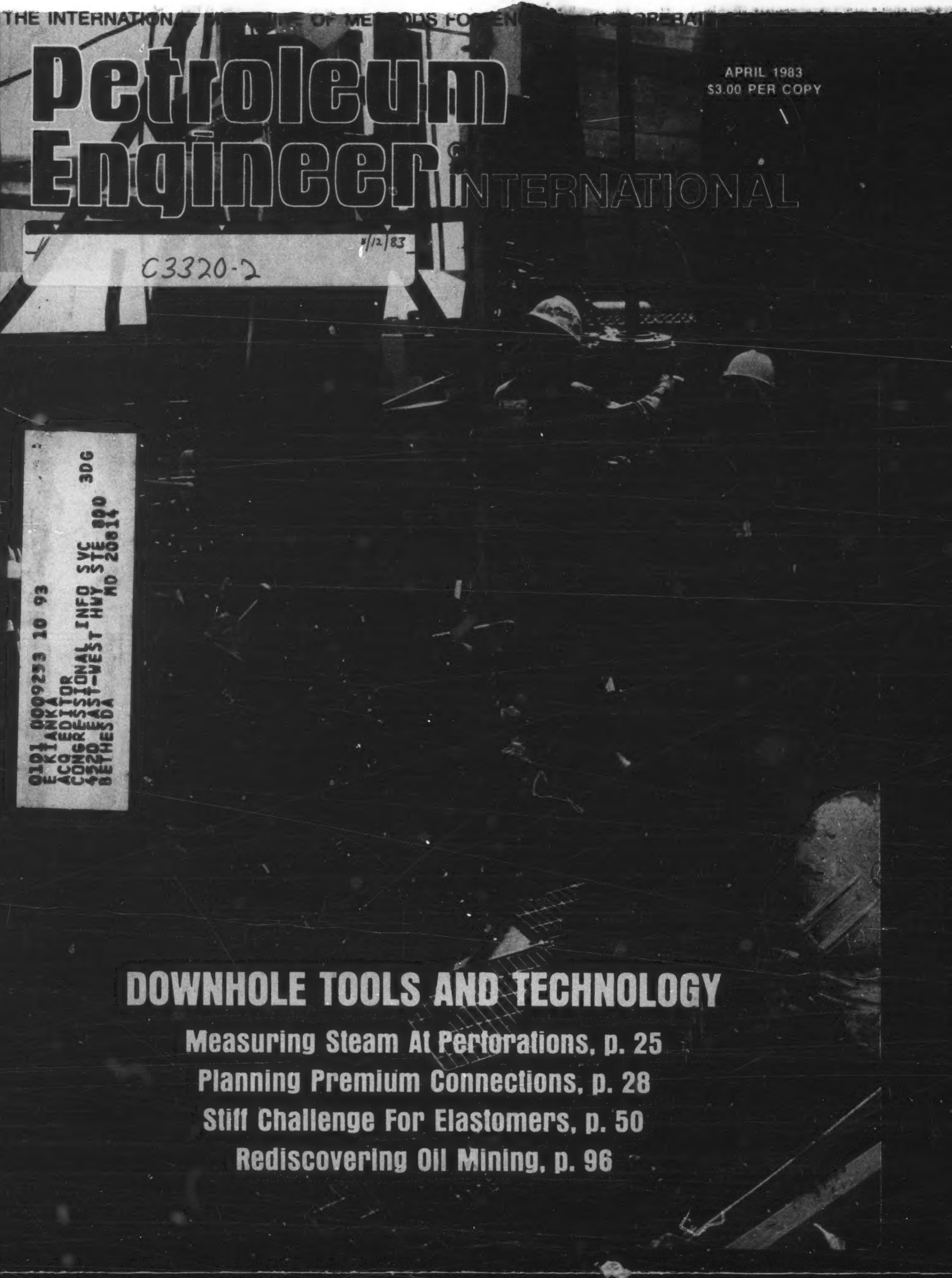

DOWNHOLE TOOLS AND TECHNOLOGY

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ABOUT THE COVER: Using a concentric tubing rig, an offshore Louisiana well is being recompleted for Union Oil Co. of California. (Photo courtesy of Pool Offshore Co.)

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Rotary Rig Count Drops 54% Below Record High

The decline in rig activity from the all-time high of 4,467 on Jan. 4, 1982 has passed the 50% mark, and stood at 54.2% at the beginning of last month.

On a state-by-state basis, Texas is the leader in the number of active rigs lost since the national high-water mark, with 721. That is a 50% decline. Oklahoma is second, with a loss of 566 rigs, and that represents a 66% drop in rotary rig activity. Louisiana is third, with a decline of 179 rigs, but that represents a drop of only 37% – well below the national average.

Other major drilling states doing better than average include California (off 45%) and Kansas (which is even with Texas at 50%).

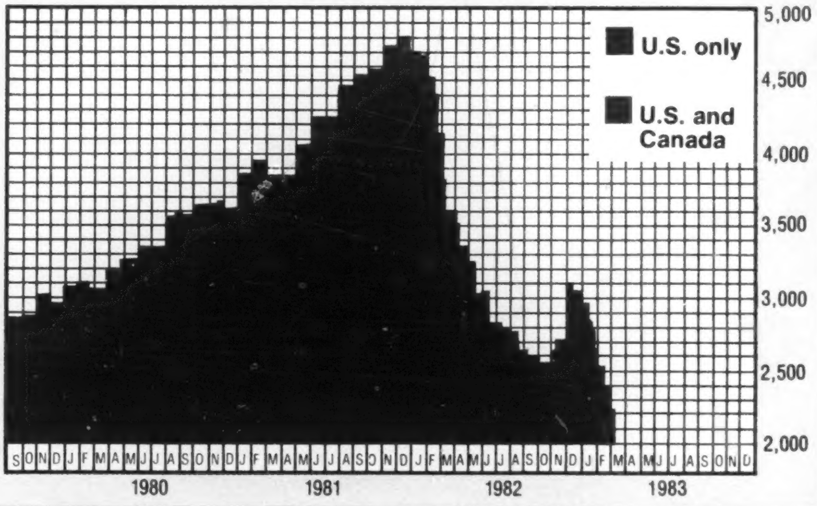
Ohio, with a drop of 73 rigs, registered a 78% decline, which was followed closely by North Dakota (down 76%). Wyoming's 149-rig decline represented a 66% drop.

If there is any award to be passed out, it probably should go to Alabama, which had 22 active rigs at the high-water mark and 22 on March 7, 1983.

Rotary Rigs Actually Making Hole In United States & Canada

As Reported To International Association Of Drilling Contractors By Hughes Tool Co.

	Feb. 14, 1983	Feb. 21, 1983	Feb. 28, 1983	March 7, 1983
Alabama				
Land	14	16	17	18
Inland Waters	4	4	4	4
Alaska				
Land	13	14	14	14
Offshore	1	1	2	2
Total	14	15	16	16
Arkansas	29	25	25	26
Arizona	0	1	1	1
California				
Land	68	74	73	73
Offshore	26	23	21	21
Total	94	97	94	94
Colorado	43	40	39	40
Florida	3	3	3	3
Hawaii	1	1	1	1
Idaho	1	1	1	1
Illinois	32	30	27	36
Indiana	5	4	5	4
Kansas	119	115	114	114
Kentucky	6	9	9	10
North Lousiana	37	28	27	24
South Louisiana				
Inland Waters	47	46	47	45
Land	91	95	91	92
Offshore	132	139	143	141
Total	307	308	308	302
Massachusetts				
Offshore	1	1	1	1
Michigan	27	24	28	23
Mississippi	30	29	33	32
Montana	25	22	22	21
Nebraska	11	10	8	9
Nevada	1	1	1	1
New Mexico	61	63	61	60
New York	13	14	6	5
North Dakota	40	42	31	28
Ohio	34	28	21	21
Oklahoma	297	285	274	283
Oregon	0	0	1	1
Pennsylvania	28	21	18	16
Tennessee	1	1	0	0
Texas				
Offshore	53	54	50	47
Inland Waters	7	9	7	8
Dist. 1-S. Central Tex.	20	22	22	21
Dist. 2-Middle Tex. Coast	36	36	31	29
Dist. 3-Upper Tex. Coast	104	92	95	92
Dist. 4-Lower Tex. Coast	103	94	75	67
Dist. 5-N.E. Tex.	25	21	19	20
Dist. 6-Far N.E. Tex.	92	88	85	81
Dist. 7B-N. Central Tex.	55	57	54	55
Dist. 7C-W. Central Tex.	69	68	58	51
Dist. 8-Far West Tex.	97	95	89	92
Dist. 8A-West Tex.	54	60	63	62
Dist. 9-North Tex.	64	60	65	66
Dist. 10-Tex. Panhandle	44	37	42	40
Total	823	793	755	731
Utah	38	37	36	33
Virginia	3	2	3	3
Washington	1	1	1	1
West Virginia	37	32	29	29
Wyoming	80	72	71	75
Total U.S.	2,223	2,147	2,064	2,043
Canada	217	242	240	243
Canada-Offshore	7	6	5	5
U.S. and Canada	2,447	2,395	2,309	2,291



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How Technology And Price Affect U.S. Tight Gas Potential

Part 2 – Economics of Tight Gas Production

Conclusion of a Two-Part Series

by Ralph W. Veatch Jr., *Amoco Production Co.*,
and Ovid Baker, *Mobil Research and Development Corp.*

In Part 1 of this series (PETROLEUM ENGINEER INTERNATIONAL, January 1983, pp. 84-96), the technology of tight gas production was described. The advancement in technology needed to develop an improved capability to drain tight gas reservoirs with fewer wells was discussed. In this concluding installment, the economics of tight gas production will be emphasized.

Economics of Tight Gas

The amount of tight gas recoverable in the lower 48 states was shown in Fig. 2 to be dependent on both the improvement in technology and the price received for the gas. As either of these factors increases, operators will be able to produce lower quality gas reservoirs, thus increasing the economically recoverable gas resources. In Fig. 2, a price scale is shown in 1978 dollars and in 1982 dollars. The difference in these prices reflects the effect of inflation over the 4-year period. The same amounts of gas are being produced, only the price has shifted.

The economics calculation procedure is described in detail in Chapter 4 of the NPC report.[1] The basis for the economics included:

- Costs and prices based on a drilling cost index = 82 (1979 = 100).
- All dollars were held constant over the entire period of producing all the gas.
- Gas prices were at point of sale in the field. All capital costs up to the sales meter including lease costs, exploration expenses, wells, wellhead equipment, gathering lines, and field compressors were included in the investment.
- Royalty was one-eighth, taxes 46% federal income tax, 2% state income tax, 8% of producer revenue for production severance and property taxes, 10%

federal investment tax credit on tangible equipment, and unit of production depletion allowance for leasehold costs. Windfall profit taxes do not apply to gas and are not included.

- Intangible drilling and development costs were expensed. Tangible equipment was capitalized and written off under 1979 rules.
- Dry hole costs, unsuccessful exploration, leasehold, and other nonrecoverable costs were charged against successful wells.
- Rates of return include all the losses from unsuccessful exploration and unsuccessful wells.
- Marginal DCF rates of return of 10%, 15%, and 20% after tax were used to select the new reservoir discoveries that would be considered productive. Wildcats that found reservoirs that could not make the marginal rate of return were considered dry wildcats and no development wells were drilled in reservoir. Thus, the lowest quality successful reservoirs had a profitability just above the marginal rate. When these were combined with the more successful ones, the average DCF was above the marginal rate.

The studies made by the NPC are made using constant dollars. There are advantages to the use of constant dollars in the economic evaluation of a proposed future project with a duration of many years. All costs and prices will change with inflation if the project is delayed a few years. If the inflation rates are exactly equal for each of the different costs and prices, the DCF rate of return on the project will remain constant even though the costs change. So the profitability of a project estimated 2 or 7 years ago may still be correct.

In practice, the inflation rate for the different materials and services involved in a project do change at different rates. This is especially so if some of them have a cyclic demand. However, even the cyclic costs and prices move together through time in a rather narrow band of variation. The DCF rate of return estimated several years in the past will still provide an approximate estimate of profitability. In a surprisingly large percentage of cases, even some changes in the assumptions about the physical properties of the gas reservoir do not change the profitability very much.

The alternate procedure involves estimating over many years the inflation rates for each item separately, which may introduce more error than it corrects.

Economic Models

The resources for each of the 82 subbasins studied by the NPC task group were estimated by a model. It incorporates the physical steps in the exploration and development process for each field in the subbasin. Investments, dry holes, production, and sales are properly scheduled to yield financial results, as well as ultimate recovery.

Input to the model comes from estimates made by geologists, production engineers, and economists who are familiar with the area under study. The simulation of an exploration play in more than one basin is accomplished by a second model which provides for scheduling investments in a number of basins over a period of years. This model makes a summation of the individual basin models just described. Output includes annual production, cash flow, and profitability.

TABLE 4. Economics summary

San Juan Basin – base case, Dakota formation

Gas price, $/Mcf		Profitable		Productive fields minimum permeability, md	Average DCF rate of return,%	Total gas recov. in basin at price, bcf
1982 dollars	1978 dollars	Prospects,%	Sections			
3.26	2.50	6	75	0.04	10	0
4.57	3.50	18	225	0.01	22	500
6.52	5.00	56	740	0.004	33	1,500
11.74	9.00	77	1,040	0.001	60	1,800

3,300 bcf in place

Table 4 illustrates the results of the analysis for one formation – the Dakota in the San Juan Basin. The results are shown for several increasing prices with a 15% DCF marginal discount rate.

Prices are shown in 1978 dollars because the NPC report is in these terms. Prices in 1982 dollars are included for the reader's convenience. Refer to the section on investment opportunities for a detailed explanation.

At $3.50/Mcf (1978 dollars) or $4.57/Mcf (1982 dollars) the third column shows 18% of the prospects profitable. We estimated there were about 85 prospects in this formation. The profitable reservoirs at this price had permeabilities in the range of 0.01 to 0.04 md. The minimum profitable permeability at $3.50/Mcf (1978 dollars) or $4.57/Mcf (1982 dollars) is shown as 0.01 md in the fifth column. Lower permeability reservoirs were unprofitable.

The average rate of return at $3.50/Mcf (1978 dollars) or $4.57/Mcf (1982 dollars) is 22% DCF. All 85 prospects are included in the average – the 15 productive ones and the 70 dry ones. The 70 dry ones lose money and the 15 profitable ones do much better than the average.

At $5.00/Mcf (1978 dollars) or $6.52/Mcf (1982 dollars), 48 are productive and 37 are dry; at $9.00/Mcf (1978 dollars) or $11.74/Mcf (1982 dollars), 65 are productive and 20 are dry.

The last column shows 500 bcf of gas recovered from these 15 fields.

To find and produce this gas would require the drilling of 200 dry wells and 500 productive wells.

At higher prices, lower permeability reservoirs can be produced and profitability gradually increases. The number of productive sections (square miles) increases from 225 at $3.50/Mcf (1978 dollars) or $4.57/Mcf (1982

TABLE 5. Geological data summary, San Juan Basin, Dakota formation

Total basin area (sections): 8,000
Type: Blanket
Depth, ft: 7,150
Pressure, psia: 3,090
Temperature, °F: 222
NGL, bbl/MMcf: 5.

						For each drilling location W/C:		
Average perm., md	Productive area, sections	H/C gas porosity, %	Net pay thickness, ft	Estimated gas in place at reservoir cond., bcf	Max. recoverable gas, bcf	Probability that state of nature is productive	Probability that W/C is productive, given that state of nature is productive 1st W/C	2nd W/C
0.04	75	5.0	10	184.13	142	0.93	0.95	1.0
0.01	150	4.0	15	441.9	321	0.93	0.95	1.0
0.004	515	3.0	20	1,517.19	1,031	0.93	0.95	1.0
0.001	300	2.25	25	828.0	526	0.85	0.95	1.0
0.0004	148	1.5	30	327.08	193	0.85	0.95	1.0
	1,188			3,298.	2,213			

dollars) to 1,040 sections at $9.00/Mcf (1978 dollars) or $11.74/Mcf (1982 dollars). The percentage recovery of the gas in place increases from 15% to 55% over this price range. No gas recovery is shown at a $2.50/Mcf price because it would not make the marginal profit of 15%.

These type calculations form the basis for the projection of a large increase in gas resources as price increases.

The San Juan Dakota resource estimating procedure was as follows:

1. Maps were prepared of each basin giving the outlines of each formation containing tight gas and measuring its area.
2. The fraction of that formation area productive of tight gas was estimated.
3. The range of permeabilities in the productive area was estimated.
4. The number of sections at each permeability level was estimated.
5. For each permeability level the (a) depth, (b) net pay, (c) porosity, and (d) pressure and temperature were estimated.
6. The gas in place was calculated for each permeability level and associated physical properties.
7. The amount of gas technically recoverable to formation abandonment pressure was calculated – usually about 10% of initial reservoir pressure.
8. The maximum recoverable gas was estimated by reducing the technically recoverable gas by a recovery adjustment factor.[1] These factors are less than one. They decrease as permeability decreases. The factors adjust for the probability of "very tight spots" within the producing field and around its borders.
9. Annual and 30-year cumulative production per well were calculated using a well production simulator model for fractured wells completed in reservoirs of each permeability level.
10. For each permeability level, the engineer calculated the number of wells required per section to produce all the gas. For current field rules, only four wells per section are allowed, so we can't produce all the gas. Often we can produce only about half of it.
11. If the formation is lenticular, the amount of the maximum recoverable gas that can be recovered depends on fracture length and number of wells per section. A model[1] was developed to calculate recovery.
12. After the recoverable gas per section is calculated, the field sizes for tight gas accumulations are estimated.
13. The exploration history of the basin was reviewed and the wildcat success percentage for each permeability level was estimated.

History and Performance, Past and Future

Gas production from the three major producing formations in the San Juan Basin – Dakota, Pictured Cliffs, and Mesa Verde – totals approximately 10.5 tcf, with the Dakota having produced more than 3 tcf. Approximately 10,200 wells have been drilled in these formations.

In delineating areas of future drilling of the Dakota in the San Juan Basin, an area was outlined around the outside of the present Dakota field limits. The outline was restricted to certain limits which were designated by the encountering of updip water or the silting out of sands.

Details of the gas potential distribution are shown in Table 5, indicating a maximum recoverable resource of 2.2 tcf.

A statistical summary of the recent exploration history and performance of the industry in the San Juan basin is shown in Table 6. Data are given for the 1960-1969 period and the 1970-1977 period. The number of wildcat wells, wildcat success rate, and amount of petroleum found per successful wildcat well are shown. These statistics are based on AAPG data with some modifications to eliminate low-risk field extension wells. These data apply to all the formations in the basin that were being explored during this period. Our estimates were limited to the thinner, lower-quality portions of the Dakota formation at the edge of the current producing area.

The 12% successful wildcats reported for the 1970-1977 period indicates that at the prices, 300-ft fractures, and quality of prospects available at that time, no more than 12% of the wells were profitable. The others were classed as dry holes and abandoned. At a price of $3.50/Mcf (1978 dollars) or $4.57/Mcf (1982 dollars) and 1,000-ft fractures with a 15% DCF marginal rate of return, our estimates indicate 18% of the wild-

TABLE 6. Exploration performance – San Juan Basin

	1960-1969			1970-1977			1960-1977		
	All wells	New fields	New pools and deeper prod.	All wells	New fields	New pools and deeper prod.	All wells	New fields	New pools and deeper prod.
Number of successful wildcat wells									
Total	82	35	47	40	38	2	122	73	49
Gas	49	10	39	15	15	0	64	25	39
Oil	26	23	3	25	23	2	51	46	5
Oil and gas	7	2	5	0	0	0	7	2	5
Amount of petroleum found									
Total, million bbl of oil equivalent*	132.6	72.1	60.5	20.9	15.5	5.4	153.5	87.6	65.9
Gas, bcf	349.0	59.0	290.0	29.6	29.6	0	279.6	88.6	290.0
Oil, million bbl	31.4	31.1	0.3	15.3	9.8	5.5	46.7	40.9	5.8
Number of wildcat wells									
Total	507	429	78	327	320	7	834	749	85
Gas†	303	257	46	123	120	3	426	377	49
Oil†	161	136	25	204	200	4	365	336	29
Oil and gas	43	36	7	0	0	0	43	36	7
Number of wildcats oil and gas per year	51	43	8	41	40	1	46	42	4
Percent wildcats successful									
Total	16.2	8.2	60.3	12.2	11.9	28.6	14.6	9.7	57.6
Gas	16.2	3.9	84.8	12.2	12.5	0	15.0	6.6	70.6
Oil	16.1	16.9	12.0	12.3	11.5	50.0	14.0	13.7	17.2
Oil and gas	16.3	5.5	71.4	—	—	—	16.3	5.6	71.4
Amount found/successful wildcat									
Total, million bbl of oil equivalent	1.6	2.1	1.3	0.52	0.41	2.7	1.3	1.2	1.3
Gas, bcf	7.1	5.9	7.4	1.97	1.97	—	5.9	3.5	7.4
Oil, million bbl	1.2	1.4	0.1	0.61	0.43	2.8	0.9	0.9	1.2
Average depth of wells									
Oil, 1,000s, ft	3.52	3.22	3.38	5.28	5.33	5.30	4.38	4.27	4.33
Gas, 1,000s, ft	7.04	6.10	6.88	5.79	5.78	5.78	6.75	5.91	6.5

*Includes gas in solution with oil and condensate produced with gas. Conversion 5.8 Mcf = 1 bbl of oil.

†Estimated by multiplying the number wildcats by the same percentage distribution as the successful wildcats.

cats would be profitable and successful.

The average discovery of 1.97 bcf per successful wildcat at 1970-1977 conditions compares with our projected discovery of 31 bcf per successful wildcat at \$3.50/Mcf (1978 dollars) or \$4.57/Mcf (1982 dollars) and 15% DCF rate of return. Note that the successful new field wildcats increased from 3.9% in the 1960s to 12.5% in the 1970s and could rise to 18% in the 1980s. The decline in reserves found per successful wildcat is an indication that the better prospects were being drilled in the 1960s. This decline is projected to be reversed by higher gas prices and longer fractures as indicated above.

Trap and Reservoir Characteristics

The Dakota of the San Juan basin is different from the producing areas of other basins in that production to some degree can be expected at most any location within the limits as defined by updip water and the silting out of the sands. In other words, localized structural traps are nonexistent and production deviations are the result of changing reservoir characteristics or localized areas of natural fractures.

The exploration simulator was programmed to take these basin characteristics into account. Table 5, the geological data summary, shows state of nature 93% productive for the first three permeability levels and 85% for the last two levels. The first wildcat drilled in a productive area is successful 95% of the time; the second, if needed, always is successful. However, a successful wildcat must meet economic criteria before going on stream and initiating field development. Table 3 shows the percent of prospects that are economically productive is much smaller. Most fields are small, 40% being below 10 bcf and 90% smaller than 60 bcf.

Production

One formation in the San Juan basin is considered potentially productive of tight gas. The productive area is 1,188 sections and the maximum recoverable gas is calculated to be 2,213 bcf.

The geological data in Table 5 are used in both the

TABLE 7. Well production summary – base case, San Juan Basin, Dakota formation

			Gas production, MMcf/year/well							
Year	K, md - 0.4	0.1	0.04	0.01	0.004	0.001	0.0004	0.0001	0.00004	0.00001
1			131	86	62	32	20			
2			84	53	35	17	10			
5			59	34	23	10	6			
10			46	26	17	8	5			
15			38	23	15	7	4			
20			31	21	14	6	3			
30			23	18	12	5	3			
30-year cum. prod., MMcf			**1,323**	**827**	**556**	**263**	**155**			

TABLE 8. Well production summary – advanced case – San Juan Basin, Dakota formation

	Gas production, MMcf/year/well									
Year	K, md - 0.4	0.1	0.04	0.01	0.004	0.001	0.0004	0.0001	0.00004	0.00001
1			289	235	202	117	76			
2			200	148	118	65	40			
5			136	97	74	38	23			
10			99	71	53	28	17			
15			81	59	44	22	14			
20			66	51	39	19	12			
30			49	42	32	16	10			
30-year cum. prod., MMcf			**2,881**	**2,171**	**1,670**	**885**	**545**			

TABLE 9. Production well requirements, San Juan Basin, Dakota formation

	Base case			Advanced case		
Permeability, md	Number of wells/section reqd. to produce all gas	Number of wells/section actually used (max = 4)	Recoverable gas from actual wells, bcf	Number of wells/section reqd. to produce all gas	Number of wells/section actually used (max = 12)	Recoverable gas from actual wells, bcf
0.04	1.4	1.4	142	0.66	0.66	142
0.01	2.6	2.6	321	1.1	1.1	321
0.004	3.6	3.6	1,031	1.2	1.2	1,031
0.001	6.6	4.	318	1.97	1.97	526
0.0004	8.3	4.	93	2.38	2.38	193
			1,905			**2,213**

reservoir and exploration simulators. The production rates estimated with the reservoir simulator for each permeability level are shown in Table 7. These rates are for base-case technology with a fracture half-length of 1,000 ft. Annual gas production in millions of cubic feet per year per well and the cumulative production over a 30-year period are given. The 30-year cumulatives range from 0.155 to 1.323 bcf per well for the five permeability levels studied.

Table 8 shows the data for the advanced technology case with fracture half-lengths of up to 4,000 ft. The 30-year cumulatives for the advanced technology case are more than 100% higher than for the base technology case for all permeability levels.

Production rates for San Juan, Dakota wells will range from about 55 Mcfd to 360 Mcfd for the first year with base technology, depending on permeability level and net pay thickness. With longer fractures, average daily production rates in the first year will range from 200 to 800 Mcfd for the various permeability levels. Rates will decline rapidly, however, and by the fifth year even the best well with advanced technology will be producing only 370 Mcfd.

The Dakota is a blanket sand and the number of wells per section actually drilled will affect the ultimate recovery drastically. Table 9 shows the number of wells per section with both base and advanced technology. With base technology, the number of wells required ranges from 1.4 to 8.3 wells per section. However, with base technology, and thus current well spacing restrictions, only four wells per section are permitted. The effect is to reduce recoverable gas from the maximum of 2,213 bcf, to only 1,905 bcf.

With advanced technology, well spacing could be varied so that the actual number of wells needed could be drilled. For the Dakota, this would range from 0.66 to 2.38 wells per section. With advanced technology, the full 2,213 bcf could be recovered.

TABLE 10. Investment and operating expenses, San Juan Basin, Dakota formation; cost index = 82 (1978)

Geology and geophysics, $/prospect	10,000
Drilling cost, $/well	250,000
Fracture cost, $/well	
– Base case (1,000 ft fracture)	93,700
– Advanced case (2,000-4,000 ft fracture)	318,000
Surface equipment, $/well	45,000
Annual operating expense, $/well	2,500
Compressor fuel cost, ratio of cost to W. I. gas revenue	0.0297

Economic Analysis

The basic geologic and production data were processed with the full cycle exploration and production simulator. The data were evaluated to determine the economics of finding and developing the gas in that particular formation. The investment and operating expenses used to evaluate the Dakota are shown in Table 10.

The output from the simulator is shown in two tables: The economic summary for the base technology case is shown in Table 11; advanced technology economics are summarized in Table 12. Evaluations are made at discount rates of 10%, 15%, and 20% at several gas prices. Each of the 24 cases shown on each table is a complete evaluation. In other words, the entire basin is drilled and developed assuming that this gas price and discount factor prevail.

In each case the table shows the rate of return and the net present value (positive only when the rate of return exceeds the discount rate). When the net present value is not positive, this simply means that none of the gas will be recoverable at this price and discount rate. In Table 11 this occurs at the lowest price of $1.50/Mcf (1978 dollars) at all discount rates, at $2.50/Mcf (1978 dollars) for discount rates of 15% and 20%, and at

TABLE 11. Economics summary

Basin San Juan
Formation Dakota
Technology Base
Date May 1980

					Average per prospect				Basin totals			Wells					
			K-levels on stream										Wildcat		Development		
Case no.	Gas price, $/Mcf*	Profit. prosp., %	no.	value**	E & P invest., $M	Gas prod., bcf	Net pres. value, $M	DCF rate of return, %	Gas recover. at price, bcf	Max. recov. GIP, bcf	Max no. prosp. at price	Wildcat success, %	Dry	Prod.	Dry	Prod.	Total
Discount rate 10%																	
1601111	1.50	6.2	1	C	1,357	1.889	–292	3.7	—	—	—	5.3	—	—	—	—	—
21	2.50	17.6	2	CD	3,420	5.527	392	13.8	463	463	84	15.1	83	15	120	480	697
31	3.10	56.2	3	CDE	12,477	16.165	1,690	15.8	1,494	1,494	92	48.3	55	52	569	2,277	2,953
41	3.50	″	″	″	″	″	2,602	19.1	″	″	″	″	″	″	″	″	″
51	5.00	″	″	″	″	″	6,040	32.7	″	″	″	″	″	″	″	″	″
61	7.00	76.9	4	CDEF	19,475	21.227	11,711	40.8	1,812	2,020	85	66.1	33	65	839	3,355	4,293
71	9.00	″	″	″	″	″	17,468	59.9	″	″	″	″	″	″	″	″	″
81	12.00	88.7	5	CDEFG	24,132	23.224	26,920	77.1	1,905	2,213	82	76.3	23	73	1,010	4,040	5,145
Discount rate 15%																	
12	1.50	0	0	–	702	—	–428	0	—	—	—	0	—	—	—	—	—
22	2.50	6.2	1	C	1,357	1.889	–200	9.6	—	—	—	5.3	—	—	—	—	—
32	3.10	17.6	2	CD	3,420	5.527	259	18.5	463	463	84	15.1	83	15	120	480	697
42	3.50	″	″	″	″	″	488	21.7	″	″	″	″	″	″	″	″	″
52	5.00	56.2	3	CDE	12,477	16.165	3,202	32.7	1,494	1,494	92	48.3	55	52	569	2,277	2,953
62	7.00	″	″	″	″	″	6,400	53.0	″	″	″	″	″	″	″	″	″
72	9.00	76.9	4	CDEF	19,475	21.227	10,639	59.9	1,812	2,020	85	66.1	33	65	839	3,355	4,293
82	12.00	″	″	″	″	″	16,670	91.4	″	″	″	″	″	″	″	″	″
Discount rate 20%																	
13	1.50	0	0	–	702	—	–437	0	—	—	—	0	—	—	—	—	—
23	2.50	6.2	1	C	1,357	1.889	–304	9.6	—	—	—	5.3	—	—	—	—	—
33	3.10	″	″	″	″	″	–217	12.8	—	—	—	″	—	—	—	—	—
43	3.50	17.6	2	CD	3,420	5.527	96	21.7	463	463	84	15.1	83	15	120	480	697
53	5.00	56.2	3	CDE	12,477	16.165	1,680	32.7	1,494	1,494	92	48.3	55	52	569	2,277	2,953
63	7.00	″	″	″	″	″	4,079	53.0	″	″	″	″	″	″	″	″	″
73	9.00	″	″	″	″	″	6,479	74.5	″	″	″	″	″	″	″	″	″
83	12.00	76.9	4	CDEF	19,475	21.227	11,431	91.4	1,812	2,020	85	66.1	33	65	839	3,355	4,293

*These prices from the NPC report had a price index of 82 (1979 = 100). This index value actually occurred in 1978. To adjust prices to 1982 dollars use the 1982 index which will be available in 1983 or 1984. In this article we have estimated the 1982 index = 107 for tight gas wells and prices in this table should increase by a factor = 107/82 = 1.305. Investments should be multiplied by 1.305 also. DCF values are unchanged.

**Code:	C	D	E	F	G
	0.04	0.01	0.004	0.001	0.0004

TABLE 12. Economics summary

Basin San Juan
Formation Dakota
Technology Advanced
Date May 1980

					Average per prospect				Basin totals			Wells					
			K-levels on stream										Wildcat		Development		
Case no.	Gas price, $/Mcf*	Profit. prosp., %	no.	value**	E & P invest., $M	Gas prod., bcf	Net pres. value, $M	DCF rate of return, %	Gas recover. at price, bcf	Max. recov. GIP, bcf	Max no. prosp. at price	Wildcat success, %	Dry	Prod.	Dry	Prod.	Total
Discount rate 10%																	
1601211	1.50	17.6	2	CD	2,874	5.527	–182	7.9	—	—	—	15.1	—	—	—	—	—
21	2.50	56.2	3	CDE	7,950	16.165	2,360	23.1	1,494	1,494	92	48.3	55	52	189	757	1,053
31	3.10	″	″	″	″	″	3,802	31.7	″	″	″	″	″	″	″	″	″
41	3.50	76.4	4	CDEF	13,979	22.621	5,577	30.2	2,020	2,020	89	66.1	35	68	343	1,372	1,819
51	5.00	″	″	″	″	″	10,682	52.3	″	″	″	″	″	″	″	″	″
61	7.00	88.7	5	CDEFG	18,840	25.786	18,864	72.3	2,213	2,213	86	76.3	24	76	456	1,825	2,381
71	9.00	″	″	″	″	″	26,700	104.0	″	″	″	″	″	″	″	″	″
81	12.00	″	″	″	″	″	38,455	150.8	″	″	″	″	″	″	″	″	″
Discount rate 15%																	
12	1.50	6.2	1	C	1,552	1.889	–508	2.3	—	—	—	5.3	—	—	—	—	—
22	2.50	56.2	3	CDE	7,950	16.165	1,018	23.1	1,494	1,494	92	48.3	55	52	189	757	1,053
32	3.10	″	″	″	″	″	2,039	31.7	″	″	″	″	″	″	″	″	″
42	3.50	″	″	″	″	″	2,720	37.5	″	″	″	″	″	″	″	″	″
52	5.00	76.9	4	CDEF	13,979	22.621	6,529	52.3	2,020	2,020	89	66.1	35	68	343	1,372	1,819
62	7.00	88.7	5	CDEFG	18,840	25.786	12,037	72.3	2,213	2,213	86	76.3	24	76	456	1,825	2,381
72	9.00	″	″	″	″	″	17,625	104.0	″	″	″	″	″	″	″	″	″
82	12.00	″	″	″	″	″	26,007	150.8	″	″	″	″	″	″	″	″	″
Discount rate 20%																	
13	1.50	0	0	–	1,039	—	–620	0	—	—	—	0	—	—	—	—	—
23	2.50	17.6	2	CD	2,874	5.527	–128	17.4	—	—	—	15.1	—	—	—	—	—
33	3.10	56.2	3	CDE	7,950	16.165	1,068	31.7	1,494	1,494	92	48.3	55	52	189	757	1,053
43	3.50	″	″	″	″	″	1,582	37.5	″	″	″	″	″	″	″	″	″
53	5.00	″	″	″	″	″	3,517	59.7	″	″	″	″	″	″	″	″	″
63	7.00	76.9	4	CDEF	13,979	22.621	7,874	84.0	2,020	2,020	89	66.1	35	68	343	1,372	1,819
73	9.00	88.7	5	CDEFG	18,840	25.786	12,416	104.0	2,213	2,213	86	76.3	24	76	456	1,825	2,381
83	12.00	″	″	″	″	″	18,799	150.8	″	″	″	″	″	″	″	″	″

*These prices from the NPC report had a price index of 82 (1979 = 100). This index value actually occurred in 1978. To adjust prices to 1982 dollars use the 1982 index which will be available in 1983 or 1984. In this article we have estimated the 1982 index = 107 for tight gas wells and prices in this table should increase by a factor of 107/82 = 1.305. Investments should be multiplied by 1.305 also. DCF values are unchanged.

**Code:	C	D	E	F	G
	0.04	0.01	0.004	0.001	0.0004

(Continued)

$3.10/Mcf (1978 dollars) for a discount rate of 20%. As price increases, net present value becomes positive and some gas becomes recoverable. For example, in Case 32, at a 15% rate of return and $3.10/Mcf (1978 dollars), present value is $259,000 and 463 bcf of gas become recoverable. Note also that permeability levels from 0.04 to 0.01 md will be economic.

All lower permeability levels were tested by wildcats but proved uneconomic. As price increases, both net present worth and recoverable gas increase; i.e., at $9.00/Mcf (1978 dollars), gas from permeability levels from 0.04 to 0.0001 md is recoverable. However, the base case recovery is still less than the maximum which could be recovered with advanced technology, as shown in Table 12.

The tables also show the investment required per prospect and the maximum number of prospects available in the basin at the price. The total number of wells required is also shown. Comparison of Tables 11 and 12 will show the effect of advanced technology.

Investment Opportunities

These same procedures were used to evaluate each of the 82 subbasins. The results are all given in the NPC report.[1] Variations in profitability between subbasins are quite large. The range of the variations, indicated in Table 13, shows that investors should be very selective in choosing areas for exploration. All of the economics are based on the assumption that the gas can be sold fairly promptly after a reasonable productive capacity has been developed in the newly discovered field. This encourages drilling near pipelines that need to buy gas. Many of these subbasins cannot be developed adequately until new pipelines are built into the area. Shut-in gas wells can reduce profitability fast.

TABLE 13. Ranking of tight gas investments; DCF rates of return expected using current technology

1982 price $/Mcf index = 107	3.26	4.57	6.52
1978 price $/Mcf index = 82	2.50	3.50	5.00
Basin or trend	**DCF for selected subbasins**		
Southwest recompletions	5-49	14-78	23-122
Uinta	37-84	22-119	33-163
Green River	20-58	21-90	21-132
Wind River	19-44	26-75	30-118
Piceance	18-31	21-48	39-65
Edwards lime	24	15-36	18-55
Cotton Valley	22	34	50
Northern Great Plains/Williston	17-29	15-39	16-52
San Juan	10	22	33
Val Verde, Sonora, and Ozona	0-9	6-15	18-21
Denver	0	0	4

The prices in Table 13 are related by changes in drilling cost in tight gas areas. The NPC report attempted to make all costs in constant dollars as of Jan. 1, 1979. The project was started in late 1978 and IPAA drilling cost data[3] for 1979 were not published until February 1981. The NPC report was issued in December 1980. The task group used 1977 IPAA drilling cost data and increased them by 18.72% as an approximation of Jan. 1, 1979 costs. Later data indicate that this cost level occurred during 1978. The index number for the prices in the NPC report is 82.0.

TABLE 14. Assumptions of competitive tight gas prices, 1982-2000

Year	Tight gas drilling cost index	Adjusted NPC specific tight gas prices from index = 82.0 to year in table, $/Mcf 2.50	3.50	5.00	Assumed wellhead market price for gas, based partly on crude oil prices, $/Mcf
1976	52.0	1.58	2.22	3.17	
1977	69.1	2.11	2.95	4.21	
1978	85.5	2.61	3.65	3.81	
1979	100.0	3.04	4.27	6.10	
1980	96.4	2.93	4.11	5.88	
1981	108.8	3.32	4.64	6.63	
1982 est.	107.0	3.26	4.57	6.52	5.27
Assumed					
1983	113.7	3.47	4.85	6.93	4.69
1984	120.5	3.67	5.14	7.35	4.69
1985	127.7	3.89	5.45	7.79	4.97
1986	135.4	4.12	5.78	8.26	5.27
1987	143.5	4.38	6.13	8.75	5.59
1988	150.7	4.59	6.43	9.19	5.92
1989	158.2	4.82	6.75	9.65	6.28
1990	166.1	5.06	7.09	10.13	6.65
1995	212.0	6.46	9.05	12.92	10.23
2000	270.	8.23	11.52	16.46	15.74

Investors must take a look into future costs and prices. The NPC report[1] (p. 28, Part 1) gave an estimate based on high inflation rates. Another estimate, based on low inflation rates, is shown in Table 14. As the price of gas has increased, consumers have begun to conserve energy and seek lower cost fuels. The result has been uncertainty about future prices[4] of gas, and some gas transmission companies have exercised price reduction options in recent contracts.

An index for tight gas drilling costs was based on drilling cost per foot in the depth range of 7,500 to 9,999 ft. This is the depth of many of the tight gas reservoirs. These costs per foot were taken from the states of Colorado, New Mexico, Texas District 6, Utah, and Wyoming where much of the tight gas resource is located. The 1979 index is equal to 100. The index values for some recent years are given in Table 14 for the period 1976 to 1981. About a 5% decline is assumed for 1982 with increases of 6% per year for 1983 to 1988, and 5% per year from 1989 to 2000.

These indexes were used to adjust constant dollar NPC prices to current NPC prices for years 1976 to 2000. These adjusted NPC prices were compared with

TABLE 15. Type of tight gas areas being drilled in 1979-1982 period*

Permeability range, md	microdarcies	Tight gas area, requested for approval, millions of acres	Percent of area	Percent of formations
0.1-0.03	100-30	65.4	66	64
0.03-0.01	30-10	27.1	28	26
0.01-0.003	10- 3	3.6	4	7
0.003-0.001	3- 1	2.1	2	3
0.001-0.0003	1- 0.3	0	0	0
Less than 0.1	<100	52		
		150.2	100	100

*Reference: *Oil and Gas J.* (April 26,1982) 69; (May 3, 1982) 100.

TABLE 16. U.S. potential tight gas production rates, tcf/year

	1978 price, $/Mcf (Index = 82)	1980	1985	1990	1995	2000
From reserves discovered before 1980		0.8	0.6	0.5	0.4	0
From reserves discovered in 1980 and later	$2.50 and 15% DCF	0	0.1	1.1	3.2	5.8
From reserves discovered in 1980 and later	$3.50 and 15% DCF	0	0.1	1.3	4.2	7.0
From reserves discovered in 1980 and later	$5.00 and 15% DCF	0	0.2	1.8	5.2	8.3
From reserves discovered in 1980 and later	$9.00 and 15% DCF	0	0.2	2.5	6.8	10.5

assumed wellhead gas prices based on 80% of crude oil energy equivalent prices.

The comparison of NPC adjusted prices and market prices indicates that the resource and production schedules for the $2.50/Mcf Case (Index = 82) could be profitable for all years through 2000. Since the $3.50/Mcf (1978 dollars) Case (Index = 82) adjusted prices for most forward years are only 3% to 10% greater than the market prices, many of these resources may be profitable also. The $3.50/Mcf (1978 dollars) Case is shown profitable for the 1990-2000 period.

Current Tight Gas Developments

Tight gas development has been proceeding more rapidly than many had anticipated. The regulatory agencies have responded quickly to operator applications for classifying tight gas areas so that they may qualify for the incentive ceiling prices if they can find buyers willing to pay that much. Table 15 summarizes data on recent developments.

By April 1982, applications to drill more than 8,000 tight gas wells had been received by the Federal Energy Regulatory Commission. Over 6,000 wells have been drilled. Some 140 operators have applied to FERC for tight gas sand designation of 100 formations covering 243,000 sections. This is about 24% of the estimated prospective area for tight gas in the lower 48 states. Approved tight gas areas are located in 15 states.

Operators are being cautious in selecting tight gas areas for drilling. Although the tight gas ceiling price is over $5.27/Mcf (1982 dollars), some purchasers are reluctant to pay these prices. Competition from coal and heavy fuel oil is expected to grow stronger in the coming years. Operators have tended to concentrate their wells nearer large markets. They also have avoided the lower permeability formations. About 94% of the approved tight gas areas and 90% of the formations are in the 0.01 to 0.1 md range of permeability.

The NPC report[1] made future production estimates of tight gas based on price and potential resources. These estimates are given in Table 16 for several gas prices in terms of 1978 dollars (Index = 82).

These production rates are potential only. This amount of tight gas could be produced if there is a market for it at the prices indicated. The prices for the year indicated are estimated in Table 14 for low inflation rates. The U.S. has a large potential gas energy resource when we need it.

Acknowledgement. The authors express their appreciation for the support of Amoco Production Co., Mobil Oil Co., and the National Petroleum Council in the completion of this work and for their permission to publish it. The authors were members of the NPC-Unconventional Gas Committee – Tight Gas Reservoirs Task Group and served as chairman and coordinator of the portion of the task group effort pertinent to technology needs. They would like to thank the other members of the task group and the special assistants for their contributions. The members were: Lucio D'Andrea, DOE; Peter J. Cover, NPC; Dr. Claude P. Coppel, Chevron Oil Field Research; Charles J. Crowley, El Paso Natural Gas; Dr. John N. Dew, Conoco; Dr. John D. Haun, Colorado School of Mines; Keith V. Hawkins, Natural Gas Pipeline Co. of America; Dr. Stephen A. Holditch, Texas A&M; F. Glenn Martin, Arco Oil & Gas; James A. Momper, Consultant; R. J. Saucier, Shell Development; Dr. Alvin L. Schalge, Marathon Oil; Charles W. Spencer and Frank W. Stead, USGS; G. W. Sullivan, Gulf Oil Exploration and Production; and James R. Weber, Chandler & Associates. Special assistants were Confidence W. O. Amadi, Mobil Research & Development; Dr. J. P. Brashear, Lewin & Associates; Robert D. Carter, Amoco Production; John S. Conway, DOE; T. D. Cook, Shell Oil; Sandra J. Dougherty, Amoco Production; Lloyd E. Elkins, Lewin & Associates; John H. Evans, David C. Faecke, David V. Findley, and John L. Fitch, Mobil Research & Development; James H. Griffith, Mobil Oil; Carrol F. Knutson, C. K. GeoEnergy; Robert L. Mann, C.E.R. Corp.; Charles N. Needham, Mobil Producing Texas & New Mexico; Dudley D. Rice, USGS; Mustafa Sengul, Marathon Oil; Fred L. Stricklin, Kirby Exploration; and Allen A. Stripling, Stripling Associates.

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Ralph W. Veatch Jr. is a research supervisor of fracturing at the Amoco Production Co. Research Center, Tulsa, Okla. He earned BS and MS degrees in petroleum engineering and a PhD in engineering science from the University of Tulsa and is a registered professional engineer in Louisiana, Oklahoma, and Texas. He worked previously as a petroleum engineer with Amoco in Louisiana, Mississippi, and Texas, and was an associate professor in petroleum engineering at the University of Southwestern Louisiana in Lafayette. He has worked in well completion, well stimulation, and fracturing research with Amoco for 10 years. In 1978 he was an SPE Distinguished Lecturer on massive hydraulic fracturing.

Veatch is active in numerous SPE committees and has been a past director of the Mid-Continent and Evangeline local sections. He served 2 years as an active member of a National Petroleum Council Task group studying U.S. tight gas reservoirs. He is currently a director of the SPE Mid-Continent Section, a member of the API Subcommittee on the Evaluation of Fracturing Materials, and chairman of the API Production Research Technical Advisory Committee on the Rheological Characterization of Fracturing Fluids.

Ovid Baker has sought solutions to the economic and technical challenges of the natural gas industry since 1939. He had assignments as research engineer, process engineer, economist, and research planner for Magnolia Petroleum and Mobil Oil. His current title is economist, Mobil Research and Development Corp.

Baker has published 22 technical papers dealing with gas and gas-liquid pipelines, phase behavior, gas processing, economics, and risk analysis. He holds 13 U.S. patents including 5 in subsea production systems. He has served as chairman of engineering committees for AGA, API, Gas Processing Association, AIChE, and the National Petroleum Council's Tight Gas Reservoirs Task Group. He received a BS in chemical engineering from Texas Tech University, and the College of Engineering of that university named him a Distinguished Engineer in 1976. He also was honored for Outstanding Achievements in Chemical Engineering in 1967 by the Dallas section of the Institute for Chemical Engineers in recognition of his contributions to two-phase and multiphase flow in pipelines. ■

Circle 242 on Reader Service Card

Drilling Expenditures Reach $36 Billion In U.S. In 1981

Total expenditures for drilling and equipping oil and gas wells and dry holes in the U.S. in 1981 amounted to more than $36 billion, an increase of $13 billion, or 60.8%, over 1980.

Average cost per well during 1981, however, registered an increase of only 23.4% — from $367,682 in 1980 to $453,691 in 1981. According to the 1981 Joint Association Survey on Drilling Costs, average cost per foot that year came to $94.30. Average well depth was 4,811 ft. The survey, which is sponsored by the American Petroleum Institute, the Independent Petroleum Association of America, and the Mid-Continent Oil and Gas Association, says that the total number of wells drilled in 1981 increased by 30.3%, and the total footage drilled increased by 31.3%.

Offshore, the total cost of wells completed in 1981 amounted to more than $5.5 billion, an increase of 44.3% over 1980. The total number of offshore wells increased 16% over 1980, while the average depth decreased by 0.6%. The average cost per foot offshore in 1981 was $384.87, an increase of 25.1%.

Breaking 1981's wells down by oil, gas, and dry-hole categories, the survey finds that the average depth of oil wells completed in 1981 was 4,183 ft, an increase of 2%. Average cost per foot in 1981 was $80.40, an increase of 21.2% over the previous year.

The average depth of gas wells in 1981 was 5,718 ft, a 1.5% increase over 1980. Average cost per foot was $122.17, compared with $95.16 in 1980.

Dry holes were drilled to an average depth of 5,154 ft in 1981, an increase of 0.9%. Average cost per foot was $90.03, a 22.2% increase over 1980.

Estimated per-well costs for drilling and equipping wells in the U.S., by depth intervals (1981)

		Total number of wells Average footage drilled and average costs			
Depth interval, ft		Oil wells	Gas wells	Dry holes	Total
0-1,249	wells	6,140	718	2,136	8,994
	Avg footage	834	887	740	816
	Avg costs $	38,997	45,783	31,155	37,677
1,250-2,499	wells	7,200	2,545	3,357	13,102
	Avg footage	1,796	2,002	1,869	1,855
	Avg costs $	86,069	80,016	58,805	77,907
2,500-3,749	wells	7,910	2,877	4,780	15,567
	Avg footage	3,150	3,213	3,188	3,173
	Avg costs $	155,023	150,280	98,262	136,718
3,750-4,999	wells	5,316	3,466	4,426	13,208
	Avg footage	4,377	4,276	4,371	4,349
	Avg costs $	240,387	205,612	150,422	201,114
5,000-7,499	wells	5,659	3,335	4,678	13,672
	Avg footage	6,100	6,044	6,078	6,079
	Avg costs $	431,507	416,199	303,507	383,977
7,500-9,999	wells	4,860	2,090	2,528	9,478
	Avg footage	8,641	8,613	8,594	8,622
	Avg costs $	820,180	943,823	741,798	826,539
10,000-12,499	wells	1,204	1,351	1,460	4,015
	Avg footage	10,953	11,041	11,096	11,034
	Avg costs $	1,593,626	1,803,737	1,531,762	1,641,830
12,500-14,999	wells	364	666	740	1,770
	Avg footage	13,351	13,546	13,539	13,503
	Avg costs $	2,670,053	3,096,781	2,602,164	2,802,235
15,000-17,499	wells	60	326	319	705
	Avg footage	15,976	16,162	16,034	16,088
	Avg costs $	4,328,184	5,078,961	4,177,631	4,607,229
17,500-19,999	wells	11	116	91	218
	Avg footage	18,397	18,567	18,544	18,549
	Avg costs $	6,403,588	8,046,313	7,289,930	7,647,685
20,000 & over	wells	1	43	43	87
	Avg footage	21,248	21,881	21,884	21,875
	Avg costs $	10,802,432	9,711,230	12,604,923	11,153,989
Totals	wells	38,725	17,533	24,558	80,816
	Avg footage	4,183	5,718	5,154	4,811
	Avg costs $	336,289	698,576	463,984	453,691

Expenditures for drilling and equipping wells in the U.S. during 1980 and 1981.

	Oil wells		Gas wells		Dry holes		Total wells	
	1980	1981	1980	1981	1980	1981	1980	1981
Wells drilled	28,553	38,725	15,225	17,533	18,233	24,558	62,011	80,816
Footage drilled (000)	117,066	161,982	85,820	100,258	93,145	126,561	296,031	388,800
Total expenditures, millions*	$7,768	$13,023	$8,167	$12,248	$6,865	$11,395	$22,800	$36,665
Average depth (ft)	4,099	4,183	5,636	5,718	5,108	5,154	4,773	4,811
Average cost per well*	$272,070	$336,289	$536,402	$698,576	$376,525	$463,984	$367,682	$453,691
Average cost per foot*	$66.36	$80.40	$95.16	$122.17	$73.70	$90.03	$77.02	$94.30

*Includes all money paid for drilling and equipping wells through the Christmas tree.

On a state-by-state basis, almost a third of 1981's $36-billion drilling tab was spent in Texas, where 25,139 wells cost more than $12 billion, or $477,782 apiece. Average depth of Texas wells was 5,369 ft.

Louisiana's drilling bill came to more than $7 billion for 5,619 wells. They were drilled to an average total depth of 6,692 ft, and they cost an average of $1,269,385 to drill and complete.

Oklahoma's 11,639 wells cost more than $5 billion, or an average of $450,544 apiece. Total depth in the Sooner State averaged 4,975 ft.

Alaska continues to be the most expensive state in which to drill. Total expenditures there topped $672 million in 1981 for 156 wells drilled to an average total depth of 10,277 ft. Average cost per well came to $4,312,574. Much of this cost is weather-related, of course, but average depth also is a major contributor. Wells in the Sunshine State, for example, cost more than $2 million apiece, despite their weather advantage. Florida's 25 wells were drilled to an average total depth of 12,626 ft in 1981. Their total tab came to more than $56 million.

Conversely, Kentucky's 1,940 wells cost only $54,750 apiece. Their average total depth was 1,514 ft. Likewise, Indiana's 803 wells cost an average of $59,807 in 1981. Their average total depth was 1,910 ft.

The country's 16,527 exploratory wells cost an average of $737,265 in 1981. Their total depth averaged 6,117 ft. Development drilling accounted for some two-thirds of the year's expenditures. Average cost for the 64,289 development wells came to $380,791. Their average total depth was 4,474 ft.

Drilling Rig For Tunisian Desert

USS Oilwell Supply Co. International has completed a 20,000-ft drilling rig for Compagnie Tunisienne de Forage (CTF) for service in the southern desert of Tunisia.

The rig, done on a turnkey basis, features a 142-ft mast with 1 million-lb static hook capacity. Because it will work remote areas, redundancy was designed into the rig's systems. The SCR house features three 5-ton air conditioners, the mud cleaning facilities are heavier than normal, and the mud tanks feature eight zinc anodes in each tank because of the highly alkaline water.

International Rig Count Reflects Global Decline

The Middle East, helped in no small measure by the return of Iran and Iraq to Hughes Tool Co.'s International Rotary Drilling Rig Report, was the only region of the world to begin 1983 with a rig count that was higher than at the same time last year.

Biggest loser during the period was Latin America, which was off by 56 rigs — 33 of them traceable to Mexico. Europe was down by 19 rigs, and African activity declined by 17. The South Pacific was off by 12.

Despite an overall decline of 48 rigs during the January-to-January period, it is interesting to note that the number of offshore rigs actually increased — by 19. Even Latin America was ahead offshore, despite its overall decline. And, only Europe showed a decline in offshore activity.

The most active Free World country (not counting the U.S. and Canada) continues to be Mexico.

International Rotary Rig Report, prepared by Hughes Tool Co.

(Figures in parentheses indicate how many of each country's rigs are offshore rigs.)

	Jan. 1982	Dec. 1982	Jan. 1983
Africa			
Algeria	77	90	80
Angola	8(6)	13(9)	13(9)
Benin	0	1(1)	1(1)
Cameroun	6(6)	7(6)	7(6)
Chad	1	1	1
Gabon	15(11)	10(8)	10(8)
Guinea Rep.	0	1(1)	1(1)
Ivory Coast	6(6)	5(5)	5(5)
Libya	33(2)	28(1)	23(2)
Morocco	6(1)	5	5
Niger	5	1	1
Nigeria	28(9)	21(11)	21(11)
Rep. of Congo	7(2)	5(1)	5(1)
Rep. of Zaire	3(1)	2(1)	2(1)
Senegal	0	1	1
Sierra Leone	0	1(1)	1(1)
South Africa	2(2)	2(2)	2(2)
Sudan	2	3	3
Tunisia	11(3)	11(3)	11(3)
	210(52)	208(53)	193(54)
Europe			
Austria	10	8	11
Denmark	2(2)	2(2)	2(2)
France	30(2)	13	13
Germany	30	31	33
Greece	6(3)	4(2)	4(2)
Holland	18(9)	23(15)	16(12)
Italy	33(8)	37(7)	37(7)
Norway	12(12)	12(12)	11(11)
Portugal	1	1	1
Spain	12(3)	10(4)	10(4)
Switzerland	1	1	1
United Kingdom	62(58)	53(50)	56(53)
Yugoslavia	22	25	25
	239(97)	220(92)	220(91)
Far East			
Bangladesh	4	4	2
Brunei	8(7)	13(9)	13(9)
Burma	31	34(1)	34(1)
India	49(8)	54(12)	54(12)
Indonesia	87(29)	93(33)	90(33)
Japan	21(6)	19(2)	19(2)
Malaysia	14(14)	11(11)	11(11)
Pakistan	19	18	18
Philippines	17(3)	12(1)	10(1)
Taiwan	5	0	0
Thailand	8(5)	7(4)	9(4)
	263(72)	265(73)	260(73)
Latin America			
Argentina	66(4)	70(1)	62(1)
Barbados	1	1	1
Bolivia	13	8	7
Brazil	92(31)	100(36)	100(34)
Chile	6(3)	6(3)	6(3)
Colombia	25	21(1)	22(1)
Costa Rica	0	1	1
Dominican Rep.	1	0	0
Ecuador	6(1)	6(1)	5(1)
Guatemala	7	4	3
Mexico	220(19)	187(22)	187(22)
Paraguay	1	0	0
Peru	25(5)	18(5)	18(5)
Trinidad	15(7)	10(5)	11(5)
Venezuela	64(16)	68(18)	63(18)
	542(86)	500(92)	486(90)
Middle East			
Abu Dhabi	35(16)	44(27)	44(27)
Bahrain	1	1	1
Dubai	3(2)	2(1)	4(2)
Egypt	30(19)	39(21)	40(22)
Iran	0	11(2)	11(2)
Iraq	5	28	28
Kuwait	3	5	5
Oman	11	12(2)	12(2)
Gatar	6(3)	3(1)	4(2)
Ras al Khaimah	1	2(1)	2(1)
Saudi Arabia	29(13)	28(12)	28(12)
Sharjah	3(1)	2	1
Syria	16	15	15
Turkey	26	33	33
Umm al Qaiwain	1	1	1
	170(54)	226(67)	229(70)
South Pacific			
Australia	38(9)	27(10)	26(11)
New Zealand	2(1)	1	1
Papua New Guinea	0	0	1(1)
	40(10)	28(10)	28(12)
Totals	**1,464 (371)**	**1,447 (387)**	**1,416 (390)**

Southeast Search For Sonat And Champlin

Sonat Exploration Co. and Champlin Petroleum Co. are conducting a joint oil and gas exploration and development program in Alabama, Georgia, and Tennessee. The two companies hold leases on approximately 510,000 acres in the southern Appalachian Mountains.

New Guidelines For Rig-Hand Protection

New federal guidelines for protecting workers exposed to kelly bushings and portions of rotary tables used on drilling rigs have been approved by the Occupational Safety and Health Administration (OSHA) following a review of guarding standards as they apply to drilling equipment.

"The success of the experiment con-

Industry-wide slump keeps profits down

Petroleum industry profits continued to be adversely affected by poor economic conditions worldwide. The 65 oil companies responding to our survey report a 19.9% drop in earnings for the fourth quarter and a 19.8% decrease for the year. Profit margin for the group fell from 5.1% to 4.4%.

Mobil Corp.'s earnings dropped 52% in the fourth quarter, from $587 million to $282 million. U.S. oil earnings fell due to higher exploration expenses, low crude prices, and reduced demand for natural gas. Foreign oil earnings plunged 44% because of reduced liftings in the Middle East, higher exploration expenses, higher tax provisions in Norway, and lower crude prices.

Throughout 1982, petroleum supply exceeded demand, causing downward pressure on petroleum prices. As a result, Texaco reported a 39.6% decline in earnings for the quarter and a 44.5% drop for the year. The company also blamed OPEC for failing to recognize the realities of the marketplace, regarding both demand and the impact of spot market activity.

Gulf Oil's fourth quarter earnings dropped 24.5%, from $301 million to $226 million. Earnings for the year fell 26.9%. Gulf's chairman, James E. Lee, is not surprised that demand for the company's products fell for the third year in a row, "with much of industrial America flat on its back and the economies of Canada and Western Europe in a recession." The most seriously affected areas of Gulf's business was refining, marketing, and chemicals. Lower interest income, coupled with higher interest expense, also reduced net income.

Increased crude oil production, higher natural gas prices, and lower exploration expense and dry hole costs, generally offset the negative impact of lower crude prices, lower natural gas production, and higher writeoffs at Shell Oil. Net income for the quarter fell from $458 million to $438 million, a 4.4% decline. Earnings for the year were down 5.6%.

Sun Co. reported a 66.3% drop in earnings for the fourth quarter and a 50.1% decline for the year. Profit from U.S. exploration and production fell to $145 million from $165 million and after-tax costs of $22 million due to trimming of its workforce contributed to the decline.

Higher exploration expenses and increased interest costs combined to cause a 2.9% drop in net income for the quarter and a 3.5% decrease for the year at Standard Oil (Ohio).

Atlantic Richfield's earnings for the year increased slightly to $1.676 billion from $1.671 billion in 1981. Increased production of crude oil from the North Slope of Alaska, higher prices for natural gas, and improved earnings from refining and marketing were the principle reasons for the increase. Net income for the quarter fell 7.6%.

Smaller losses for overseas downstream operations and higher Canadian petroleum earnings were behind Standard Oil (Indiana)'s 8.1% fourth quarter gain in net income. Earnings for the year were down 5%, benefiting from a significant recovery in U.S. refining, marketing, and transportation activities.

Exxon reported earnings in the fourth quarter of $1.48 billion compared to $1.38 billion in the same period of 1981, an increase of 6.9%. For the year, net income dropped 13.3%, from 4.18 billion in 1982 to $4.82 billion in 1981.

Higher charges attributable to their expanded exploration program, reduced American Petrofina's net income in the fourth quarter to $14.8 million, a 12.7% decline from 1981's $16.9 million. Earnings for the year dropped 26.6%.

Belco Petroleum reported a 5.3% increase in net income for the quarter and a 5.8% rise for the year, due primarily to higher natural gas production and prices in the U.S., higher oil and gas production in Peru, and higher oil and gas production coupled with significantly

OIL COMPANIES' FOURTH QUARTER FINANCIAL REPORTS

	Three months ending December 31**						Twelve months ending December 31**						Profit Margin	
	Revenues ($000)			Earnings* ($000)			Revenues ($000)			Earnings* ($000)				
Company	1982	1981	% Chg.	1982	1981	% Chg.	1982	1981	% Chg.	1982	1981	% Chg.	1982	1981
Amerada Hess	2,116,414	2,339,424	- 9.5	43,613	48,248	- 9.6	8,394,085	9,443,630	- 11.1	168,662	212,591	- 20.7	2.0	2.3
American Petrofina	530,350	531,209	- 0.2	14,835	16,989	- 12.7	2,253,678	2,522,154	- 10.6	54,401	74,140	- 26.6	2.4	2.9
Argonaut Energy	623	2,366	- 73.7	(677)	164		2,221	5,870	- 62.2	2,606	(151)		17.3	
Ashland Oil	2,079,812	2,409,350	- 13.7	23,722	42,020	- 43.5	8,780,340	9,885,230	- 11.2	124,586	94,592	+ 31.7	1.4	1.0
Asamera							449,241	470,593	- 4.5	3,597	9,693	- 62.9	0.8	2.1
Atlantic Richfield	7,095,135	7,140,262	- 0.6	434,007	469,818	- 7.6	26,990,557	28,208,255	- 4.3	1,676,078	1,671,290	+ 0.3	6.2	5.9
Belco Petroleum	98,330	82,333	+ 19.4	27,769	26,366	+ 5.3	344,367	317,098	+ 8.6	104,034	98,350	+ 5.8	30.2	31.0
Brock Exploration[1]	2,280	2,808	- 18.8	215	558	- 61.5	5,370[2]	6,267[2]	- 14.3	(350)[2]	581[2]			9.3
Callon Petroleum[3]	6,193	3,627	+ 71.0	75	327	- 77.1	21,510	11,432	- 88.2	1,446	1,689	- 14.4	7.0	15.0
Commonwealth Oil Refin.	19,800	203,500	- 90.3	23,800	175,700	- 86.4	307,800	1,012,900	- 69.6	45,900	258,700	- 82.3	14.9	25.5
Crown Central	497,202	422,061	+ 17.8	4,598	14,865	- 69.1	1,782,000	1,502,000	+ 18.6	7,016	3,362	+108.7	0.4	0.2
Damson Oil[4]	71,803	49,766	+ 44.3	6,134	5,096	+ 20.4							8.5	10.2
Diamond Shamrock	755,339	872,548	- 13.4	46,196	59,733	- 22.7	3,177,379	3,376,215	- 5.9	149,543	230,156	- 35.0	4.7	6.8
Dorchester Gas[3]	409,516	228,299	+ 79.4	5,614	5,450	+ 3.0	1,159,101[6]	712,033[6]	+ 62.8	17,812[6]	31,287[6]	- 43.1	1.5	4.4
Dyco Petroleum	12,810	13,759	- 6.9	3,597	4,624	- 22.2	56,509	49,182	+ 14.9	15,532	14,992	+ 3.6	27.5	30.5
Engle Exploration[1]	1,080	153	+605.9	(650)	(114)		2,524[2]	569[2]	+343.6	(1,411)[2]	(234)[2]			
Enstar Corp.	80,479	100,589	- 20.0	11,125	8,812	+ 26.3	342,796	360,842	- 5.0	42,103	41,567	+ 1.3	12.3	11.5
Equity Oil	6,334	6,192	+ 2.3	1,364	1,292	+ 5.6	23,674	24,951	- 5.1	3,268	5,572	- 41.3	13.8	22.3
Exxon	26,393,545	29,756,561	- 11.3	1,480,932	1,385,215	+ 6.9	103,558,545	114,922,561	- 9.9	4,185,932	4,826,215	- 13.3	4.0	4.2
Felmont	19,450	22,820	- 14.8	3,005	4,353	- 31.0	77,472	79,091	- 2.0	14,037	16,749	- 16.2	18.1	21.2
Forest Oil Corp.	36,410	38,523	- 5.5	2,109	1,507	+ 40.0	152,465	142,335	+ 7.1	12,009	5,104	+135.3	7.9	3.6
Freeport McMoRan	191,831	199,754	- 4.0	(17,447)	26,059		747,888	835,404	- 10.5	65,946	159,366	- 58.6	8.8	19.1
General American	88,907	85,645	+ 3.8	12,985	18,557	- 30.0	347,883	354,016	- 1.7	59,009	59,680	- 1.1	17.0	16.9
Getty Oil	3,000,878	3,472,840	- 13.6	172,445	216,266	- 20.3	12,311,612	13,251,560	- 7.1	690,712	855,902	- 19.3	5.6	6.5
Gulf Energy & Develop.	27,718	17,652	+ 57.0	1,308	2,981	- 56.1	91,110	60,132	+ 51.5	5,102	8,047	- 36.6	5.6	13.4
Gulf Oil Corp.	8,160,000	7,935,000	+ 2.8	226,000	301,000	- 24.9	30,658,000	30,461,000	+ 0.7	900,000	1,231,000	- 26.9	2.9	4.0
Holly Corp.[7]	104,255	129,794	- 19.7	5,445	5,398	+ 0.9	539,628	412,438	+ 28.7	10,516	5,672	+ 85.4	1.9	1.4
Inexco Oil	47,476	62,621	- 24.2	4,070	9,596	- 57.6	217,539	238,738	- 8.9	18,865	31,921	- 40.9	8.7	13.4
Louisiana L&E	331,302	342,791	- 3.3	23,173	18,533	+ 25.0	1,205,175	1,277,539	- 5.7	76,252	145,229	- 47.5	6.3	11.4
Mapco Inc.	540,701	581,242	- 7.0	19,695	31,114	- 36.7	1,992,947	2,179,034	- 8.5	73,822	96,890	- 23.8	3.7	4.4
Maynard Oil							33,307	43,799	- 23.9	(3,399)	4,520			10.3
Mesa Petroleum	103,295	99,399	+ 3.9	27,712	28,120	- 12.1	406,963	407,744	- 0.2	115,945	106,379	+ 9.0	28.5	26.1
Mitchell Energy[8]	255,785	285,666	- 10.5	22,446	35,280	- 36.4	961,713	1,064,844	- 9.7	80,303	115,217	- 30.3	8.4	10.8
Mobil Corp.	16,184,000	18,095,000	- 10.6	282,000	587,000	- 52.0	63,828,000	68,587,000	- 6.9	1,380,000	2,433,000	- 43.3	2.2	3.6
Murphy Oil	714,914	684,686	+ 4.4	40,141	38,458	+ 4.4	2,698,840	2,543,380	+ 6.1	159,093	163,006	- 2.4	5.9	6.4
Natomas	441,322	441,359		(8,367)	48,807		1,655,786	1,582,396	+ 4.6	44,000	232,527	- 81.1	2.7	14.7
Noble Affiliates	91,526	106,166	- 13.8	9,858	21,972	- 55.1	408,787	394,606	+ 3.6	70,261	80,281	- 12.5	17.2	20.6
Oxoco	12,402	12,723	- 2.5	2,139	2,768	- 22.7	39,226	28,340	+ 38.4	7,392	5,563	+ 32.9	18.8	19.6
Pacific Resources	395,270	314,559	+ 25.7	6,873	9,608	- 28.5	1,237,219	1,081,477	+ 14.4	9,798	17,106	- 42.7	0.8	1.6
Pennzoil Co.	529,144	652,982	- 19.0	50,486	54,778	- 7.8	2,268,511	2,681,751	- 15.4	188,713	221,642	- 14.9	8.3	8.3
Petro-Lewis	92,646	53,829	+ 72.1	7,931	4,312	+ 84.0	240,700[9]	180,000[9]	+ 33.7	17,200[9]	30,400[9]	- 43.4	7.1	7.9
Prairie Producing Co.	5,539	7,425	- 25.4	1,857	730	+154.4	25,570	30,061	- 14.9	5,259	6,758	- 22.2	20.6	22.5
Phillips Petroleum	4,062,727	4,091,181	- 0.7	154,593	186,526	- 17.1	15,891,612	16,287,753	- 2.4	645,856	879,364	- 26.6	4.1	5.4
Premier Resources[4]	2,963	3,518	- 15.8	(2,319)	(1,326)		13,185	12,061	+ 9.3	(1,691)	(345)			
Presidio Oil	3,486[9]	3,918[9]	- 10.9	255[9]	498[9]	- 48.8	1,727	1,924	- 10.2	105	183	- 42.6	6.1	9.5
Quaker State	210,144	229,177	- 8.3	7,216	6,747	- 7.0	928,933	918,913	+ 1.1	38,568	27,367	+ 41.0	4.2	3.0
Sabine Corp.	49,706	46,749	+ 6.3	3,017	5,628	- 46.3	197,422	172,670	+ 14.3	24,450	28,342	- 13.7	12.4	16.4
Shell Oil	5,176,000	5,193,000	- 0.3	438,000	458,000	- 4.4	20,214,000	21,739,000	- 7.0	1,605,000	1,701,000	- 5.6	7.9	7.8
Southland Royalty	83,374	99,054	- 15.8	4,884	8,895	- 45.1	357,925	400,139	- 10.5	28,659	36,216	- 20.9	8.0	9.1
Southwestern Energy	16,660	13,315	+ 25.1	4,675	2,991	+ 56.3	62,712	54,756	+ 14.5	13,020	12,533	+ 3.9	20.8	22.9
Standard Indiana	7,500,000	7,800,000	- 3.8	415,000	384,000	+ 8.1	29,900,000	31,700,000	- 5.7	1,826,000	1,922,000	- 5.0	6.1	6.1
Standard Ohio	3,216,700	3,773,300	- 14.7	463,900	477,800	- 2.9	13,529,200	14,140,200	- 4.3	1,879,100	1,946,900	- 3.5	13.9	13.8
Statex Petroleum[8]	3,003	3,368	- 10.8	(72)	581									17.3
Sun Co.	4,100,000	4,500,000	- 8.9	151,000	448,000	- 66.3	16,300,000	16,400,000	- 0.6	537,000	1,076,000	- 50.1	3.3	6.6
Superior Oil	504,100	560,500	- 10.1	24,000	73,200	- 67.2	2,040,500	2,057,400	- 0.8	223,400	361,300	- 38.2	10.9	17.6
Tenneco	3,978,100	4,312,200	- 7.8	288,000	260,000	+ 10.8	15,396,300	15,383,100	+ 0.1	819,000	813,000	+ 0.7	4.9	4.9
Tesoro[4]	604,368	652,750	- 7.4	9,627	19,376	- 50.3	2,439,853	3,034,768	- 19.6	42,518	73,583	- 42.2	1.7	2.4
Texaco Inc.	11,700,000	14,600,000	- 19.9	306,000	507,000	- 39.6	48,000,000	59,300,000	- 19.1	1,281,000	2,310,000	- 44.5	2.7	3.9
Tomlinson Oil[3]	24,447	27,100	- 9.8	(216)	(865)									
Tosco Corp.	913,745	901,492	+ 1.4	3,054	30,095	- 90.0	3,465,964	3,431,491	+ 1.0	132,312	22,579	+486.4	3.8	0.7
Total Petroleum N.A.	583,772	654,938	- 10.9	5,248	(14,667)		2,233,056	2,380,538	- 6.2	12,752	(63,608)		0.6	
Union Oil of California	2,736,100	2,911,400	- 6.0	225,100	236,000	- 4.6	10,899,100	11,296,200	- 3.5	804,000	791,400	+ 1.6	7.4	7.0
Universal Resources	12,599	17,282	- 27.0	(115)	3,679		58,117	63,707	- 8.8	6,609	13,601	- 51.4	11.4	21.4
Woods Petroleum	22,088	22,900	- 3.5	6,483	8,632	- 24.9	83,048	71,969	+ 15.4	23,018	21,897	+ 5.1	27.7	30.4
Worldwide Energy	17,367	16,338	+ 6.0	1,262	568	+122.2	58,777	54,474	+ 7.9	857	(574)		1.5	
TOTAL	117,073,267	128,231,763	- 8.7	5,486,525	6,846,218	- 19.9	461,869,469	499,649,530	- 7.6	20,474,523	25,522,789	- 19.8	4.4	5.1

**Excluding non-recurring items. *Earnings available to common stock. ( ) Loss. [1] Ends March 31. [2] Nine months. [3] Ends Nov. 30. [4] Ends Sept. 30. [6] Ends Aug. 31. [7] Ends July 31. [8] Ends Jan. 31. [9] Six months.

higher oil prices and tax credits in Canada.

Callon Petroleum's fourth quarter earnings fell 77.1%, from $327,000 to $75,000. Net income for 1982 dropped to $1.4 million from $1.6 million in 1981, a 14.4% decline.

While gas processing, refining and marketing-terminalling operations improved, contract drilling and industrial equipment sales posted substantial losses at Dorchester Gas, resulting in a 43.1% drop in earnings for 1982. Net income for the quarter however, increased 3%.

Enstar's 1982 net income increased slightly to $42.1 million, compared with 1981 earnings of $41.6 million due to decreased interest expense and a lower after-tax charge for the redemption fund of the Virginia International Company Special Stock. Fourth quarter earnings increased 26.3%.

Lower level of dry hole expense improved fourth quarter results considerably at Equity Oil where net income increased 5.6%. For the year, however, earnings dropped 41.3%, from $5.57 million in 1981 to $3.26 million in 1982.

Felmont Oil reported earnings of $3 million for the fourth quarter 1982 compared to $4.35 million in 1981, a 31% drop-off. Net income for the year fell 16.2%, from $16.7 million to $14 million.

Hampered by customer gas curtailment, soft liquid prices, and higher feedstock costs, Gulf Energy & Development's earnings dropped 56.1% for the quarter and 36.6% for the year.

The worldwide slowdown in economic activity adversely affected Louisiana Land and Exploration's earnings for 1982 which dropped 47.5%. Lower oil, copper, and refined product prices as well as decreased demand for copper and natural gas contributed significantly to the decline. Net income for the quarter increased 25% due to a lower effective tax rate, improved real estate sales, and a reduction in overhead and petro-

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GAS COMPANIES' FOURTH QUARTER FINANCIAL REPORTS

	Three months ending December 31**						Twelve months ending December 31**							
	Revenues ($000)			Earnings* ($000)			Revenues ($000)			Earnings* ($000)			Profit Margin	
Company	1982	1981	% Chg.	1982	1981	% Chg.	1982	1981	% Chg.	1982	1981	% Chg.	1982	1981
Alabama Tennessee N.G.	36,277	30,263	+ 20.0	1,542	1,651	- 6.6	132,872	116,805	+ 13.8	5,858	5,786	+ 1.2	4.4	5.0
ARKLA	316,247	282,333	+ 12.0	10,166	8,386	+ 21.2	1,296,584	1,179,139	+ 1.0	95,380	87,560	+ 8.9	7.4	7.4
Coastal Corp.	1,582,419	1,314,797	+ 20.4	22,582	1,929	+1070.7	5,818,797	5,925,476	- 1.8	65,630	(20,399)		1.1	
Columbia Gas	1,407,690	1,351,070	+ 4.2	64,357	74,357	- 13.0	5,070,591	4,426,243	+ 14.6	180,063	194,085	- 7.2	3.6	4.4
Consolidated N.G.	883,670	810,597	+ 9.0	37,312	37,942	- 1.7	3,210,985	2,738,164	+ 17.3	155,420	131,656	+ 18.1	4.8	4.8
El Paso Companies	1,188,990	1,127,620	+ 5.4	(12,926)	39,409		4,364,042	3,909,023	+ 11.6	53,236	147,257	- 63.8	1.2	3.8
ENSERCH Corp.	913,433	852,953	+ 7.1	25,747	46,140	- 44.2	3,787,675	3,362,474	+ 12.6	157,353	196,959	- 20.1	4.2	5.8
InterNorth	1,188,406	1,029,812	+ 15.4	30,799	60,937	- 49.5	4,158,986	3,641,567	+ 14.2	181,275	253,512	- 28.5	4.4	7.0
Kansas-Nebraska N.G.	135,086	133,311	+ 1.3	8,516	6,911	+ 23.2	488,319	451,037	+ 8.3	26,452	25,574	+ 3.4	5.4	5.7
National Fuel Gas	276,932	267,766	+ 3.4	6,777	12,308	- 44.9	1,006,714	912,438	+ 10.3	27,048	27,846	- 2.9	2.7	3.1
Northwest Energy	599,514	452,847	+ 32.4	29,130	18,008	+ 61.8	1,601,832	1,377,259	+ 16.3	60,238	68,107	- 11.6	3.8	4.9
NOVA, An Alberta Corp.	1,054,973	798,675	+ 32.1	32,473	20,378	+ 59.4	3,501,798	2,669,551	+ 31.2	91,181	97,028	- 6.0	2.6	3.6
ONEOK Inc.	255,422	274,518	- 7.0	8,113	12,317	- 34.1	1,088,620	1,109,843	- 1.9	49,988	59,078	- 15.4	4.6	5.3
Pacific Lighting	1,196,123	1,006,128	+ 18.9	39,208	18,897	+107.5	4,404,395	3,401,489	+ 29.5	122,946	117,225	+ 4.9	2.8	3.4
Panhandle Eastern	880,075	803,229	+ 9.6	35,368	48,664	- 27.3	3,391,465	3,266,253	+ 3.8	219,876	216,604	- 16.0	6.5	8.0
Peoples Energy	335,971	367,077	+ 8.7	4,548	11,119	- 59.0	1,511,384	1,395,243	+ 8.3	39,381	50,228	- 21.6	2.6	3.6
Pioneer Corp.	252,579	317,516	- 20.5	18,688	25,206	- 25.9	1,118,736	1,224,645	- 8.6	91,244	110,204	- 17.2	8.2	9.0
Sonat Inc.	747,598	728,047	+ 2.7	43,999	44,643	- 1.4	2,737,696	2,629,003	+ 4.1	204,639	173,672	+ 17.8	7.5	6.6
Texas Eastern Corp.	1,502,728	1,242,618	+ 20.9	13,382	60,124	- 77.7	5,654,353	4,526,114	+ 24.9	161,334	220,634	- 26.9	2.9	4.9
Texas Gas Transmission	770,205	764,851	+ 0.7	27,399	25,981	+ 5.5	2,877,590	2,649,265	+ 8.6	111,268	128,684	- 13.5	3.9	4.9
TransCanada PipeLines	899,727	925,455	- 2.8	50,905	42,592	+ 19.5	3,466,915	3,404,897	+ 1.8	161,128	125,573	+ 28.3	4.6	3.7
Transco Energy Co.	1,060,900	897,201	+ 18.2	20,899	41,286	- 49.4	3,869,329	3,475,667	+ 11.3	129,202	132,343	- 2.4	3.3	3.8
Union Gas Ltd.	301,586	280,686	+ 7.4	9,536	10,208	- 6.6	705,525[1]	621,537[1]	+ 13.5	13,669[1]	12,116[1]	+ 12.8	1.9	1.9
United Energy Res.	1,316,100	1,505,300	- 12.6	33,300	56,800	- 41.4	5,561,800	5,431,000	+ 2.4	192,400	215,700	- 10.8	3.5	4.0
Westcoast Transmission	362,114	363,904	- 0.5	14,998	19,065	- 21.3	1,153,440	1,270,330	- 9.2	70,047	65,426	+ 7.1	6.1	5.2
TOTAL	19,464,765	17,928,574	+ 8.6	576,818	734,651	- 21.5	71,980,443	65,114,462	+ 10.5	2,666,226	2,887,458	- 7.7	3.7	4.4

** Excluding non-recurring items. *Earnings available to common stock. [1]Nine months. ( ) Loss.

leum operating costs.

Natomas posted an 81.1% drop in net income for 1982. Higher interest expenses and declines from Natomas' international and domestic petroleum operations are blamed. For the quarter, the company reported an $8.4 million loss.

The depressed contract drilling market as well as a decline in oil and gas operating income caused by foreign exchange losses, high dry hole expenses, and weak natural gas demand resulted in a 55.1% decline in fourth quarter earnings for Noble Affiliates. Net income for 1982 fell 12.5%.

Oxoco's 1982 earnings increased 32.9% due primarily to higher profitability on oil and gas activities. For the quarter, net income fell 22.7%.

Sharply reduced natural gas sales, losses in the metals division, and a decrease in sulphur sales combined in 1982 for a 14.9% drop in earnings at Pennzoil for the year and a 7.8% decrease for the quarter.

Superior Oil reported a 67.2% decrease in net income in the fourth quarter and a 38.2% drop in 1982. In addition to the impact of the recession on oil and gas prices, the company experienced larger lease impairments, higher exploration and dry hole costs, and absorbed substantial losses of its mining affiliates.

In spite of a harsh recessionary economy, Tenneco posted record net income for both the year and the fourth quarter. In 1982, earnings increased from $813 million to $819 million. For the quarter, net income increased 11.8%.

Continuing depressed domestic drilling activity, reduced production levels of foreign crude oil and natural gas, and reduced domestic crude oil prices are blamed for Tesoro Petroleum's 50.3% decline in fourth quarter earnings and a 42.2% drop-off for the year.

Fourth quarter earnings at Tosco Corp. were down 90%, while net income for the year increased 486%. Even though the year was highly profitable, toward the end of 1982 a costly and destructive war to increase market position by the majors reduced gasoline prices, sometimes below the cost of crude oil, the company noted.

Lower demand for natural gas and related services contributed to a 21.5% decline in fourth quarter earnings for the 25 gas companies in our survey group. Profit margin fell from 4.4% to 3.7%.

The El Paso Company's gain in earnings from exploration and production activities, sales of natural gas liquids, and the sale of an interest in certain insurance assets was more than offset by the adverse effect of a reduction in gas market demand, reduced revenues and volumes on the sales of chemical products and higher interest expense. The company reported a loss for the quarter and a 63.8% decline in earnings for the year.

Peoples Energy's fourth quarter earnings dropped 59% due to reduced gas sales resulting from the sluggish economy, substantially warmer weather, and the loss of large-volume commercial and industrial sales to low-sulphur No. 6 oil, along with higher operating costs. For the year, net incomes declined 21.6%.

The downturn in the petroleum industry is blamed for ONEOK's 34.1% drop-off in earnings for the quarter and 15.4% decline for the year.

A decline in earnings from Pacific Lighting's utility sector was made up by a substantial increase in earnings from their federally regulated gas pipeline operations, and oil and gas exploration and production activities. Fourth quarter earnings were up 107%, while net income for the year increased 4.9%.

TransCanada PipeLines' earnings increased from $42.5 million in the previous quarter to $50.9 million in the fourth quarter. For 1982, net income was up 28.3%.

United Energy Resources' 1982 operations were adversely affected by the recession in the energy sector, resulting in a 41.4% decline in fourth quarter earnings and a 10.8% drop-off for the year. ■

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OFFSHORE TECHNOLOGY

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ABOUT THE COVER: Dual Offshore Rig 38 is shown being towed from Okpo, Korea, to the Java Sea, where it is scheduled to drill for Arco Indonesia. (Photo courtesy of Dual Drilling Co.)

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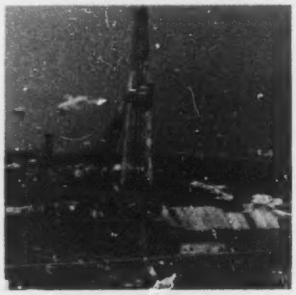
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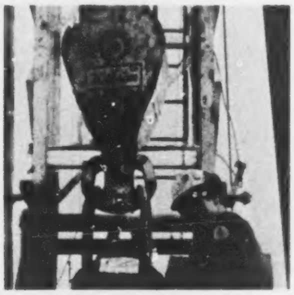
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Engineering Profits into Energy Operations

Canadian Rig Count Drops 67% In Month

The U.S. rotary rig count declined by 166 active rigs during the mid-March to mid-April period this year, which represents a loss of 8.3%. Canada, meanwhile, was down 153 rigs during the same period, and that is a decline of 67%.

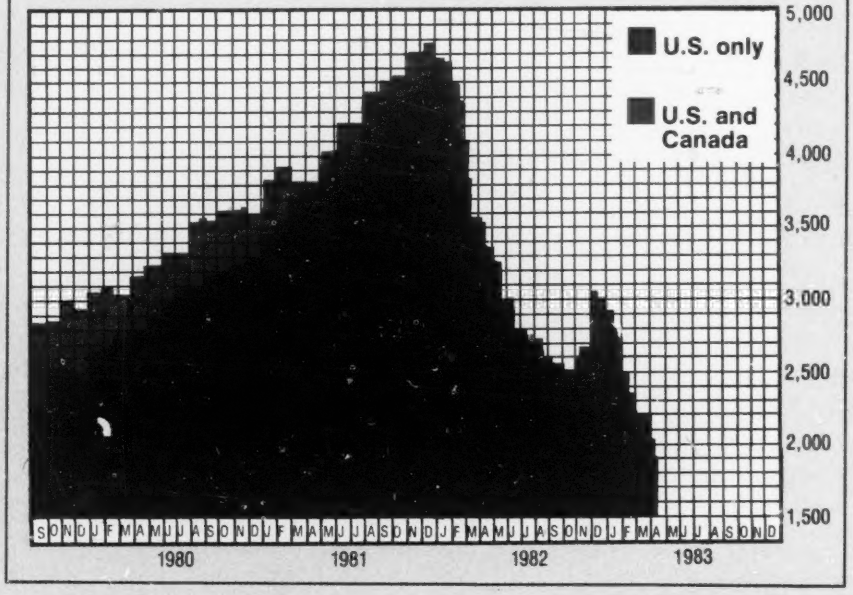
Canadian offshore activity, however, appears to be holding its own, with some observers predicting that country's offshore expenditures this year to total about $1.1 billion. And they look for them to rise to $1.4 billion in 1984.

Last year, nine rigs were active offshore Canada's east coast (seven semi-submersibles and two jackups). Six of them operated off Nova Scotia and three were in Newfoundland waters. In addition, three drillships operated offshore Labrador, and one was active in the Davis Strait. Total expenditures offshore eastern Canada last year came to approximately $630 million.

Rotary Rigs Actually Making Hole in United States & Canada

As Reported To International Association Of Drilling Contractors By Hughes Tool Co.

	Mar. 21, 1983	Mar. 28, 1983	Apr. 4, 1983	Apr. 11, 1983
Alabama				
Land	16	13	14	13
Inland Waters	4	4	4	4
Alaska				
Land	14	14	13	12
Offshore	3	2	3	3
Total	17	16	16	15
Arkansas	23	20	25	30
Arizona	1	1	0	1
California				
Land	67	66	62	65
Offshore	21	21	20	24
Total	88	87	82	89
Colorado	47	37	41	39
Florida	4	3	4	4
Hawaii	1	1	1	1
Idaho	1	1	0	0
Illinois	37	39	40	33
Indiana	1	3	4	4
Kansas	115	114	38	60
Kentucky	7	9	9	9
North Louisiana	26	24	26	21
South Louisiana				
Inland Waters	45	45	45	47
Land	94	88	77	70
Offshore	143	140	138	139
Total	308	297	286	277
Michigan	9	12	18	13
Minnesota	1	1	0	0
Mississippi	32	37	37	37
Montana	19	17	13	12
Nebraska	10	12	11	12
New Mexico	48	49	54	59
New York	6	5	3	3
North Dakota	28	24	22	21
Ohio	18	20	18	17
Oklahoma	293	292	267	250
Oregon	1	0	0	0
Pennsylvania	11	11	10	10
South Dakota	0	0	0	1
Tennessee	0	0	1	0
Texas				
Offshore	46	47	45	48
Inland Waters	7	8	9	9
Dist. 1-S. Central Tex.	18	18	22	23
Dist. 2-Middle Tex. Coast	23	34	30	32
Dist. 3-Upper Tex. Coast	93	86	86	80
Dist. 4-Lower Tex. Coast	74	72	69	63
Dist. 5-Northeast Tex.	24	25	24	24
Dist. 6-Far Northeast Tex.	79	77	74	73
Dist. 7B-N. Central Tex.	57	53	50	54
Dist. 7C-W. Central Tex.	49	49	44	45
Dist. 8-Far West Tex.	96	95	93	96
Dist. 8A-West Tex.	57	50	48	51
Dist. 9-North Tex.	61	58	60	67
Dist. 10-Tex. Panhandle	43	38	38	39
Total	726	710	692	704
Utah	26	33	33	27
Virginia	2	2	2	2
Washington	1	1	1	1
West Virginia	27	22	17	18
Wyoming	72	63	64	68
Total U.S.	2,000	1,956	1,882	1,834
Canada	227	163	101	74
Canada-Offshore	5	6	6	8
U.S. and Canada	2,232	2,125	1,989	1,916



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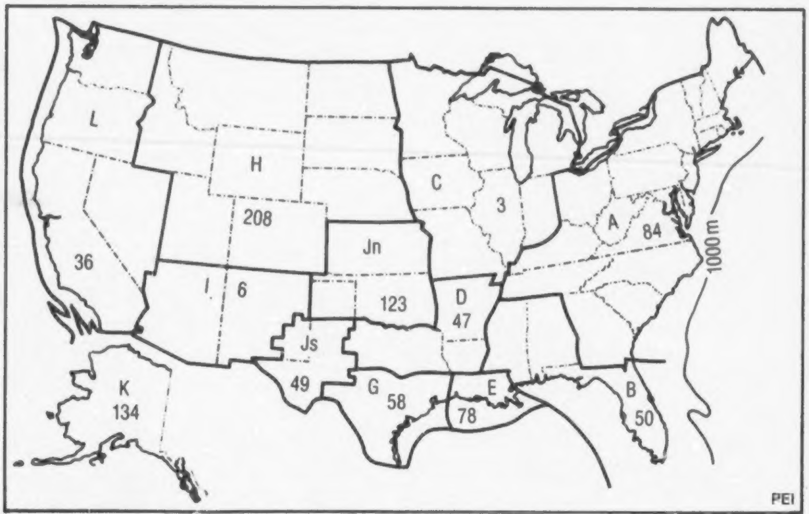
Drilling Activity Reinforces Gas Committee's Optimism

The undiscovered natural gas resource potential of the U.S. provides a foundation for meeting the nation's natural gas energy needs well into the 21st century, according to the Potential Gas Committee.

Results of accelerated drilling activity in the U.S. through 1981 and high rates of successful well completions through 1982, in addition to the previously accumulated knowledge about the nation's gas resource, have led the committee to estimate the total potential remaining gas to be discovered to be approximately 876 tcf. This is a decrease of 37 tcf from the year-end 1980 estimate.

J.C. Herrington, chairman of the Potential Gas Committee, points out that the decrease is approximately equal to the gas discovered over the past 2 years. This means that there has been no significant new information developed during the past 2 years that would have caused the committee to alter its previous concept of the potential supply. In a speech before the 10th Energy Technology Conference recently in Washington, D.C., Harrington pointed out some paradoxes in the current potential supply picture, but he stressed that results of exploration and drilling activity during the past 2 years have basically reinforced the committee's position that more than one-half of the resource originally existing in the country still remains to be found, and more than 60% remains to be produced. He said also that consumers can be assured of the existence of adequate supplies of recoverable natural gas to meet demand for the foreseeable future. In fact, he added, the industry currently has productive capacity in excess of market demands.

The national total estimate, however, is a combination of regional estimates, which have individually been increased or decreased since the committee's 1980 evaluation. Frontier areas, such as Alaska and portions of the Rocky Mountain states, tend to have major changes because exploratory plays there are in the early stages of development. The committee's estimate for the Rocky Mountain states has been increased largely because of inclusion of quantities of low-heat-content gas in western Wyoming. Additional potential also is believed to exist in some areas in central Wyoming where sedimentary rocks now are known to occur beneath major thrust faults.



Reporting areas and total potential gas supply, as seen by the Potential Gas Committee as of the end of 1982.

The committee now believes that the low-heat-content gas can be commercially developed, and that the subthrust sediments provide additional targets for exploration. Increases in the Rockies partly offset decreases in estimates for other areas.

The estimate of potential for the Mid-Continent area, particularly Oklahoma, was decreased due to transfers from potential resources to proved reserves and to better evaluation of the potential made possible by recently high levels of drilling activity. This activity confirmed some estimates, but there have been disappointments also in some areas, such as the deep Pennsylvanian Springer sands in the southeastern part of the Anadarko Basin.

The estimate for California, Oregon, Washington, and Nevada has been reduced primarily because of a reevaluation of the potential for the San Joaquin basin, plus transfers to proved reserves. Recent seismic work and wild-

TABLE 1. Estimated potential supply of natural gas (trillions of cubic feet at 14.73 psia and 60 F)

	Probable	Possible	Speculative
Lower 48 states			
Onshore	151	263	179
Offshore	33	63	53
Alaska			
Onshore	6	16	28
Offshore	2	13	69
Total U.S.	**192**	**355**	**329**

TABLE 2. Estimated potential supply of natural gas in the U.S. by geographic areas, as of Dec. 31, 1982. (Trillions of cubic feet at 14.73 psia and 60F)

Area		Probable	Possible	Speculative
A	Onshore	27	8	33
	Offshore	—*	—	16
B	Onshore	6	6	7
	Offshore	1	2	28
C	Onshore	—	2	1
D	Onshore	8	20	19
E	Onshore	6	15	—
	Offshore	21	36	—
G	Onshore	12	15	4
	Offshore	11	16	—
H	Onshore	49	93	66
I	Onshore	2	3	1
J-North	Onshore	24	60	39
J-South	Onshore	15	33	1
L	Onshore	2	8	8
	Offshore	—	9	9
48 states	subtotal	184	326	232
K Alaska	Onshore	6	16	28
	Offshore	2	13	69
	Total U.S.	**192**	**355**	**329**

*Dashes are used to represent estimates of potential of less than 0.5 tcf.

cat drilling have diminished what had been considered to be prospective acreage in Alaska – portions of the arctic basin, for example, the Gulf of Alaska, Lower Cook Inlet, and the Kodiak area.

Estimates for other areas of the country show no significant changes other than those expected by normal developments. These include the relatively mature exploration and production areas of Texas and Louisiana, which have shown consistent declines in estimates of future gas potential as their gas resources have been developed and produced.

With the coming of age of improved completion technology for tight formations, and a price incentive granted by regulatory agencies, this formerly unconventional gas resource is rapidly increasing in importance as a conventional resource. In fact, a review of all areas where the Potential Gas Committee now estimates conventional natural gas potential indicates that as much as 20% (172 tcf) of this so-called tight gas resource may be included in the current estimate.

Copies of the committee's complete report, Potential Supply of Natural Gas in the United States, as of Dec. 31, 1982, are to be released next month. It can be ordered from the Potential Gas Agency, Colorado School of Mines, Golden, Colo. 80401.

Mideast Drilling Up As Free World Slumps

Free World drilling activity declined by 35 rigs during the first 2 months of 1983, and stood at 1,381 active rotary rigs as of February, according to Hughes Tool Co.'s International Rotary Drilling Rig Report.

The decline in activity since the previous February (in 1982) was 85 rigs.

Only the Middle East failed to take part in the slump. That region, in fact, gained 56 rigs during the year. Some 34 of them are accounted for by the return to the charts in a big way by Iran and Iraq, but even if rigs from those two countries are not counted, the Middle East still registered a 17-rig gain. All other regions of the Free World (not counting the U.S. and Canada) registered losses.

International Rotary Rig Report, prepared by Hughes Tool Co.

(Figures in parentheses indicate how many of each country's rigs are offshore rigs.)

	Feb. 1982	Jan. 1983	Feb. 1983
Africa			
Algeria	68	80	80
Angola	8(6)	13(9)	13(9)
Benin	0	1(1)	1(1)
Cameroun	6(6)	7(6)	7(6)
Chad	1	1	0
Gabon	15(11)	10(8)	9(8)
Guinea	0	1(1)	0
Ivory Coast	6(6)	5(5)	3(3)
Libya	33(2)	23(2)	23(2)
Morocco	6(1)	5	5
Niger	5	1	1
Nigeria	28(9)	21(11)	19(10)
Congo	7(5)	5(4)	0
Zaire	3(1)	2(1)	2(1)
Senegal	0	1	0
Sierra Leone	0	1(1)	0
South Africa	2(2)	2(2)	2(2)
Sudan	2	3	3
Tunisia	11(3)	11(3)	11(3)
	210(52)	193(54)	179(45)
Latin America			
Argentina	68(3)	62(1)	63(1)
Barbados	1	1	1
Bolivia	13	7	7
Brazil	91(29)	100(34)	99(35)
Chile	7(3)	6(3)	6(3)
Colombia	23	22(1)	19
Costa Rica	0	1	1
Dominican Rep.	1	0	0
Ecuador	5(1)	5(1)	4
Guatemala	7	3	3
Mexico	215(19)	187(22)	187(22)
Paraguay	1	0	0
Peru	25(5)	18(5)	13(5)
Trinidad	15(7)	11(5)	12(5)
Uruguay	1	0	0
Venezuela	66(16)	63(18)	61(18)
	539(83)	486(90)	476(89)
Far East			
Bangladesh	7	2	1
Brunei	10(7)	13(9)	12(8)
Burma	31	34(1)	41(1)
India	49(8)	54(12)	54(12)
Indonesia	94(30)	90(33)	86(30)
Japan	21(6)	19(2)	19(2)
Malaysia	14(14)	11(11)	9(9)
Pakistan	16	18	18
Philippines	17(3)	10(1)	9
Taiwan	4	0	0
Thailand	9(6)	9(4)	10(5)
	272(74)	260(73)	259(67)
Europe			
Austria	10	11	9
Denmark	2(2)	2(2)	2(2)
France	30(2)	13	22
Germany	30	33	31
Greece	6(3)	4(2)	4(2)
Holland	18(9)	16(12)	16(11)
Italy	33(8)	37(7)	37(7)
Norway	12(12)	11(11)	10(10)
Portugal	1	1	1
Spain	13(6)	10(4)	9(5)
Switzerland	1	1	1
United Kingdom	63(59)	56(53)	44(41)
Yugoslavia	22	25	25
	241(101)	220(91)	211(78)
Middle East			
Abu Dhabi	38(19)	44(27)	44(27)
Bahrain	1	1	1(1)
Dubai	3(2)	4(2)	4(2)
Egypt	30(19)	40(22)	40(22)
Iran	0	11(2)	11(2)
Iraq	5	28	28
Kuwait	3	5	5
Oman	11	12(2)	12(2)
Qatar	6(3)	4(2)	4(2)
Ras al Khaimah	1	2(1)	2(1)
Saudi Arabia	29(13)	28(12)	28(12)
Sharjah	3(1)	1	1
Syria	16	15	15
Turkey	26	33	33
Umm al Qaiwain	1	1	1
	173(57)	229(70)	229(71)
South Pacific			
Australia	38(9)	26(11)	24(11)
New Zealand	2(1)	1	2
Papua New Guinea	0	1(1)	1(1)
	40(10)	28(12)	27(12)
Totals	**1,466 (377)**	**1,416 (390)**	**1,381 (362)**

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ABOUT THE COVER: The jack-up rigs Ocean Masters V and VI are shown being loaded aboard the cargo ship Dyvi Swan in Brazil's Sao Sebastia harbor prior to dry shipment to Saudi Arabia. (Photo courtesy of Loffland Brothers Co.)

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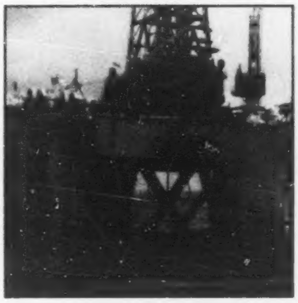

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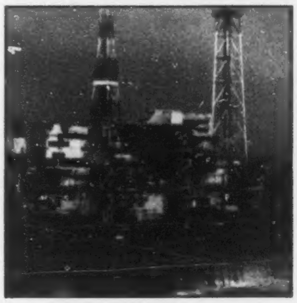

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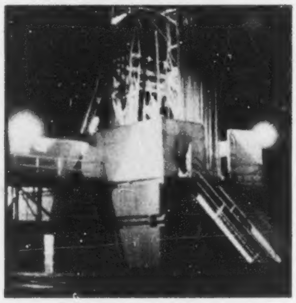

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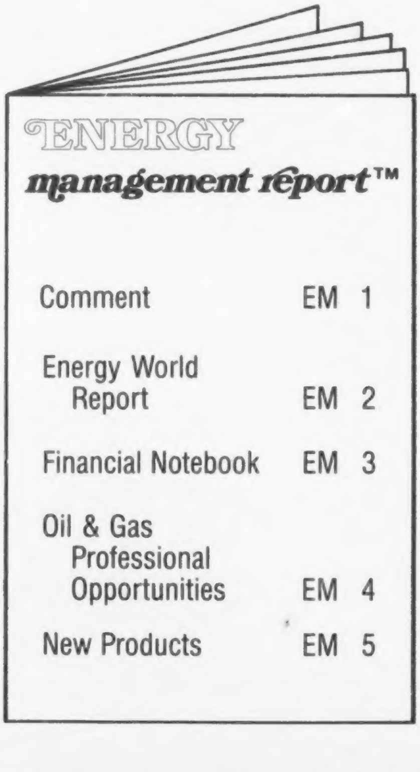

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Drillers See Light At End Of Tunnel

The long-awaited turnaround in U.S. rotary rig activity seems to have arrived on schedule, if events of late April and early May are any indication. During that time, the count increased at an average rate of 47 rigs per week after having declined at a rate of almost 60 rigs per week during the first quarter of 1983.

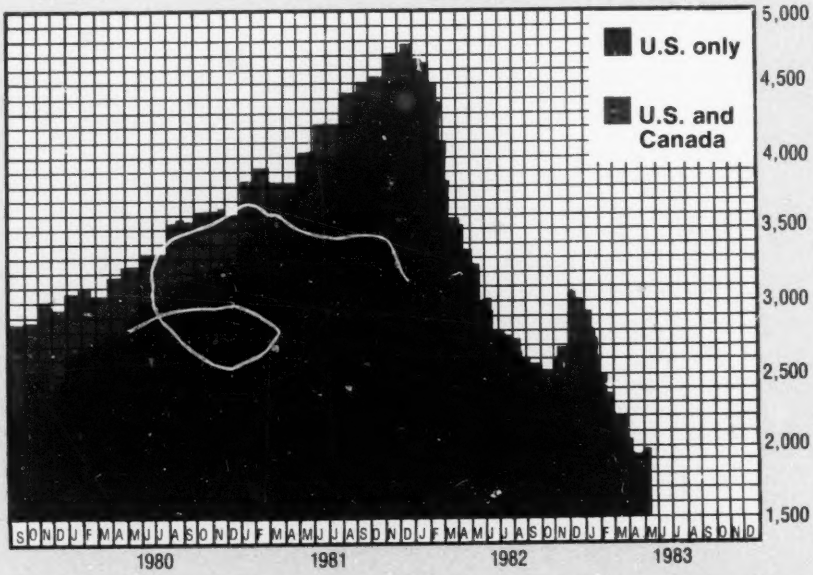
As of mid-May, the average U.S. rig count for the year stood at 2,165. The high point came on January 3, when the count stood at 2,756. Low point came 15 weeks later, on April 18, when 1,807 rotaries were turning. Since then, 141 rigs have been added to the U.S. count.

It is too early to tell whether Canada will join in the turnaround because the rig count north of the border traditionally reaches its nadir in mid-May. The 43 rigs counted in Canada on May 9 this year, however, represent the lowest rig count in that country since May 19, 1975, when the count was also 43.

Rotary rigs actually making hole in United States & Canada

As Reported To International Association Of Drilling Contractors By Hughes Tool Co.

	April 18, 1983	April 25, 1983	May 2, 1983	May 9, 1983
Alabama				
Land	9	9	12	13
Inland Waters	4	2	2	3
Offshore	0	1	1	1
Total	13	12	15	16
Alaska				
Land	12	10	10	10
Offshore	3	4	5	6
Total	15	14	15	16
Arkansas	29	23	21	20
Arizona	1	1	1	0
California				
Land	65	66	72	71
Offshore	23	25	25	20
Total	88	91	97	91
Colorado	35	39	33	36
Florida	5	6	6	5
Hawaii	1	1	1	1
Idaho	0	0	0	1
Illinois	28	29	60	54
Indiana	4	5	4	5
Kansas	54	100	111	120
Kentucky	8	5	8	9
North Louisiana	19	22	23	29
South Louisiana				
Inland Waters	50	45	45	40
Land	68	75	66	61
Offshore	137	136	130	123
Total	274	278	264	253
Michigan	11	11	14	22
Mississippi	33	27	27	26
Montana	14	13	13	13
Nebraska	12	12	12	12
Nevada	0	1	1	1
New Mexico	64	63	64	61
New York	3	6	9	5
North Dakota	23	22	25	26
Ohio	21	18	26	25
Oklahoma	239	232	268	294
Pennsylvania	9	9	9	8
South Dakota	1	1	0	0
Texas				
Offshore	50	53	56	52
Inland Waters	9	9	8	8
Dist. 1-S. Central Tex.	22	21	22	20
Dist. 2-Middle Tex. Coas	35	33	23	24
Dist. 3-Upper Tex. Coas	85	93	87	92
Dist. 4-Lower Tex. Coast	66	60	55	52
Dist. 5-Northeast Tex.	26	21	21	24
Dist. 6-Far Northeast Tex.	69	75	71	77
Dist. 7B-N. Central Tex.	61	55	60	66
Dist. 7C-W. Central Tex.	45	48	46	49
Dist. 8-Far West Tex.	91	96	84	83
Dist. 8A-West Tex.	50	50	50	55
Dist. 9-North Tex.	62	69	62	56
Dist. 10-Tex. Panhandle	38	45	44	45
Total	709	728	689	703
Utah	25	25	26	32
Virginia	2	1	1	1
Washington	1	1	1	1
West Virginia	16	19	24	24
Wyoming	69	67	68	66
Total U.S.	1,807	1,860	1,913	1,948
Canada	59	45	47	38
Canada-Offshore	9	9	9	5
U.S. and Canada	1,875	1,914	1,969	1,991



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International Report

Free World drilling activity declined by 125 rigs during the first quarter of 1983, according to Hughes Tool Co. figures which indicate that 39 of the idle rigs are offshore rigs.

At the end of 1982, the International Rotary Drilling Rig Report counted 1,447 active rigs in the Free World (not counting the U.S. and Canada). Some 387 of them were offshore rigs. The count for March 1983 is 1,322 active rotaries, of which 348 are offshore.

The activity declines seem to be pretty much across the board, with no country or region standing out. The full tally follows:

International Rotary Rig Report, prepared by Hughes Tool Co.

(Figures in parentheses indicate how many of each country's rigs are offshore rigs.)

	March 1982	Feb. 1983	March 1983
Far East			
Bangladesh	3	1	1
Brunei	12(8)	12(8)	10(7)
Burma	31	41(1)	41(1)
India	41(7)	54(12)	54(12)
Indonesia	94(31)	86(30)	87(23)
Japan	24(6)	19(2)	18(2)
Malaysia	14(14)	9(9)	9(9)
Pakistan	16	18	17
Philippines	18(4)	9	9
Taiwan	4(1)	0	0
Thailand	9(6)	10(5)	11(6)
	272(77)	259(67)	257(60)
South Pacific			
Australia	32(9)	24(11)	24(12)
New Zealand	1	2	2
Papua New Guinea	1	1(1)	1(1)
	34(9)	27(12)	27(13)
Europe			
Austria	10	9	9
Denmark	2(2)	2(2)	5(4)
France	28(2)	22	15(1)
Germany	30	31	30
Greece	6(3)	4(2)	3(1)
Holland	18(9)	16(11)	16(11)
Italy	33(8)	37(7)	33(7)
Norway	15(15)	10(10)	10(10)
Portugal	1	1	1
Spain	14(7)	9(5)	9(5)
Switzerland	1	1	1
United Kingdom	64(60)	44(41)	39(38)
Yugoslavia	22	25	25
	244(106)	211(78)	196(77)
Middle East			
Abu Dhabi	38(19)	44(27)	40(26)
Bahrain	1	1	1
Dubai	3(2)	4(2)	5(3)
Egypt	32(22)	40(22)	35(21)
Iran	0	11(2)	2
Iraq	5	28	22
Jordan	0	0	3
Kuwait	3	5	5
Oman	11	12(2)	10
Qatar	6(3)	4(2)	2(2)
Ras al Khaimah	1	2(1)	1
Saudi Arabia	31(17)	28(12)	25(12)
Sharjah	3(1)	1	0
Syria	16	15	15
Turkey	26	33	31
Umm al Qaiwain	1	1	1
	177(64)	229(71)	198(64)
Africa			
Algeria	68	80	80
Angola	8(6)	13(9)	13(9)
Benin	0	1(1)	1(1)
Cameroun	6(6)	7(6)	6(6)
Chad	1	0	0
Gabon	15(11)	9(8)	9(8)
Ivory Coast	6(6)	3(3)	2(2)
Libya	33(2)	23(2)	23(2)
Morocco	6(1)	5	5
Niger	5	1	1
Nigeria	28(9)	19(10)	19(10)
Rep. of Congo	7(5)	0	5(5)
Rep. of Zaire	3(1)	2(1)	2(1)
South Africa	2(2)	2(2)	2(2)
Sudan	2	3	5(1)
Tunisia	11(3)	11(3)	11(3)
	201(52)	179(45)	184(50)
Latin America			
Argentina	73(3)	63(1)	63(1)
Barbados	1	1	1
Bolivia	13	7	6
Brazil	93(30)	99(35)	98(34)
Chile	7(3)	6(3)	6(3)
Colombia	23	19	18
Costa Rica	0	1	1
Dominican Rep.	1	0	0
Ecuador	5(1)	4	5
Guatemala	6	3	3
Mexico	211(20)	187(22)	187(22)
Paraguay	1	0	0
Peru	26(5)	13(5)	15(6)
Trinidad	13(6)	12(5)	11(4)
Venezuela	68(17)	61(18)	46(14)
	541(85)	476(89)	460(84)
Totals	**1,469 (393)**	**1,381 (362)**	**1,322 (348)**

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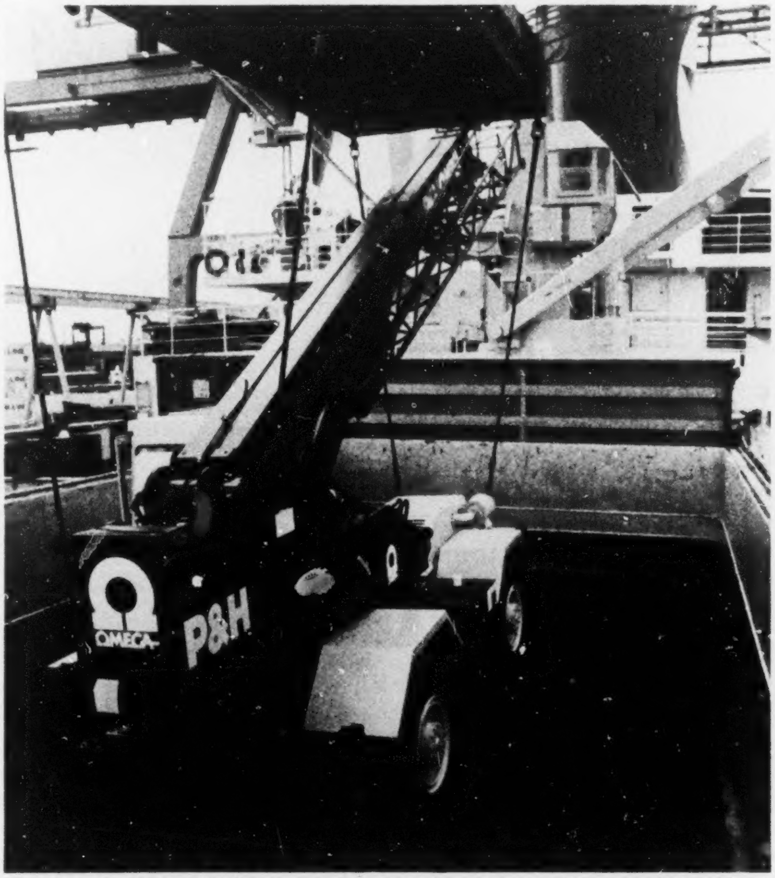


This is one of 13 hydraulic cranes that departed Los Angeles recently for direct shipment to New Zealand aboard Blue Star Line's Wellington Star. The cranes, which have lift capacities ranging between 15 and 20 tons, are to be used in construction of New Zealand's big gas-to-gasoline project.

International Deep Drilling Costs Hit $1.3 Billion

by John Wilson, *Gulf Coast Editor*

International operators spent more than $1.3 billion drilling 72 wells past 15,000 ft in 1982, making more than 1.2 million ft of hole. In addition, approximately 35 wells were still drilling at year-end after reaching the 15,000-ft mark.

The 107 deep wells completed and active in 1982 equal 10% of the record 1,205 deep wells drilled in the U.S. last year. The $1.3 billion in costs, however, come to more than 18% of the $7 billion spent on U.S. deep wells in 1982.

There were 46 operators drilling deep wells worldwide using 32 contractors. Mud costs were approximately $61 million. Drilling costs hit $1.2 billion, and completion costs totaled $63 million.

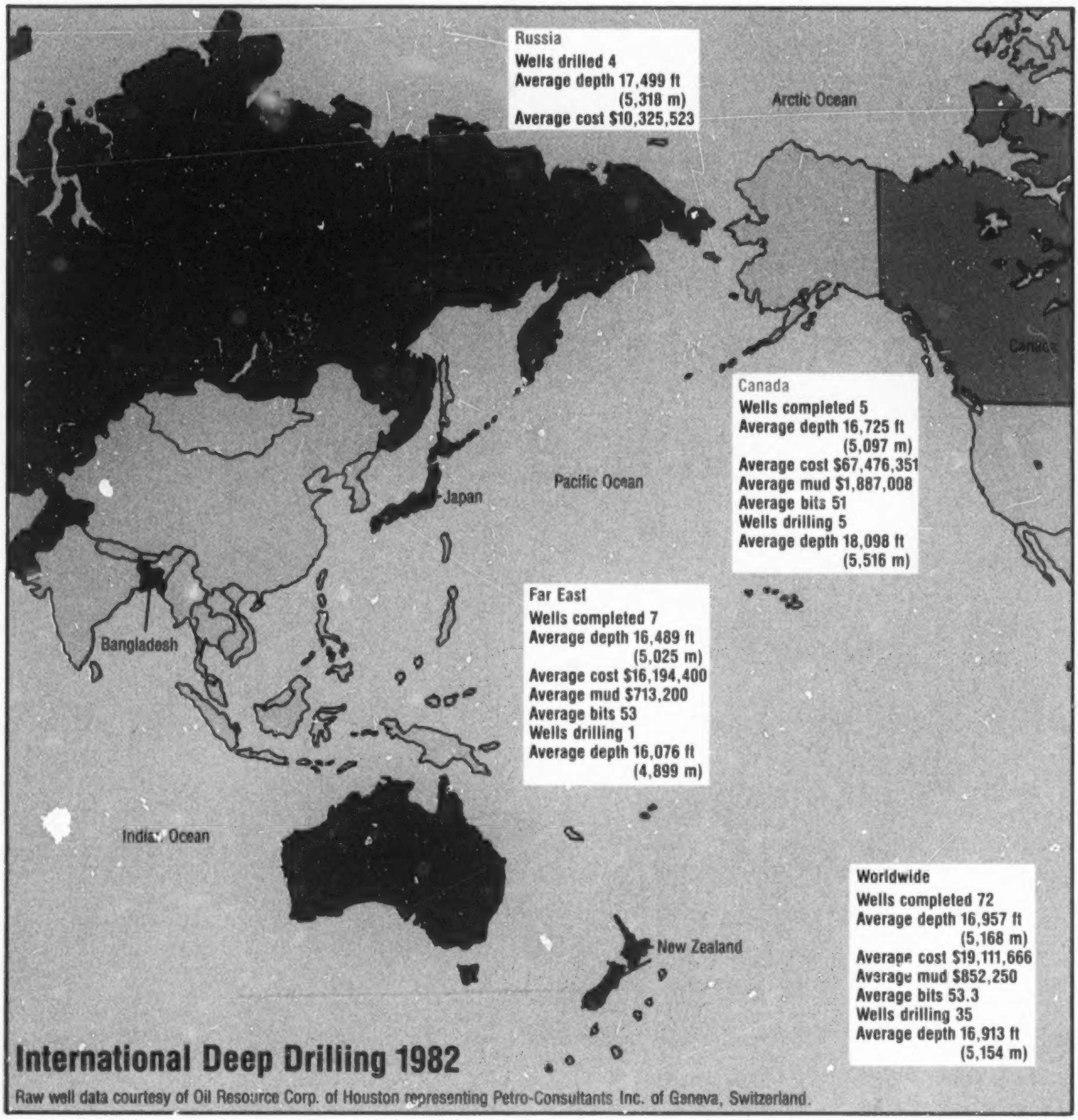
The average well cost was $19,111,666, nearly three times the U.S. average deep well cost in 1982. At first glance this is a staggering figure, especially in view of U.S. average costs, until the profile of international deep wells is considered.

More Exploratory Drilling

First, only 45% of U.S. deep wells are exploratory compared to nearly 78% worldwide. The higher percentage of development wells in the U.S. report tends to dampen cost figures because development wells are easier to plan and manage.

Second, the high percentage of deep exploratory wells worldwide was compounded by the fact that

The Zapata Ugland semisubmersible drills the Bonanza M-71 for Mobil Canada offshore Nova Scotia. The well was completed in February this year at 17,371 ft.



Russia
Wells drilled 4
Average depth 17,499 ft
(5,318 m)
Average cost $10,325,523

Canada
Wells completed 5
Average depth 16,725 ft
(5,097 m)
Average cost $67,476,351
Average mud $1,887,008
Average bits 51
Wells drilling 5
Average depth 18,098 ft
(5,516 m)

Far East
Wells completed 7
Average depth 16,489 ft
(5,025 m)
Average cost $16,194,400
Average mud $713,200
Average bits 53
Wells drilling 1
Average depth 16,076 ft
(4,899 m)

Worldwide
Wells completed 72
Average depth 16,957 ft
(5,168 m)
Average cost $19,111,666
Average mud $852,250
Average bits 53.3
Wells drilling 35
Average depth 16,913 ft
(5,154 m)

International Deep Drilling 1982

Raw well data courtesy of Oil Resource Corp. of Houston representing Petro-Consultants Inc. of Geneva, Switzerland.

nearly half those wells were drilled offshore where costs are greater.

In addition, much of the exploration activity took place in hostile environments – the North Sea, offshore Canada, desert regions, and other such frontier areas.

The large number of exploratory wells also accounts for the higher bit use average compared to U.S. deep wells. Bit usage worldwide was 53.3 compared to 37.3 in the U.S. in 1982.

The higher average is probably due to the nature of exploration drilling – formation changes often force operators to pull green bits in favor of something more suitable. Higher mud weights also slow penetration rates and cut into bit life.

As for the large percentage of deep exploration wells worldwide, many of the operators PEI interviewed felt such wells probably were being used for stratigraphic control – the best way to understand a basin is to take a well to the basement and use the hard data gathered there to calibrate seismic work in the area. Since the size of worldwide lease holdings and concessions exceeds U.S. leases by a great percentage, it is advantageous and economical to drill exploratory wells in many countries. This also accounts for the fairly even distribution of international deep wells with one or two per country in active exploration areas known for shallow production.

Operators in the areas of greatest activity, however,

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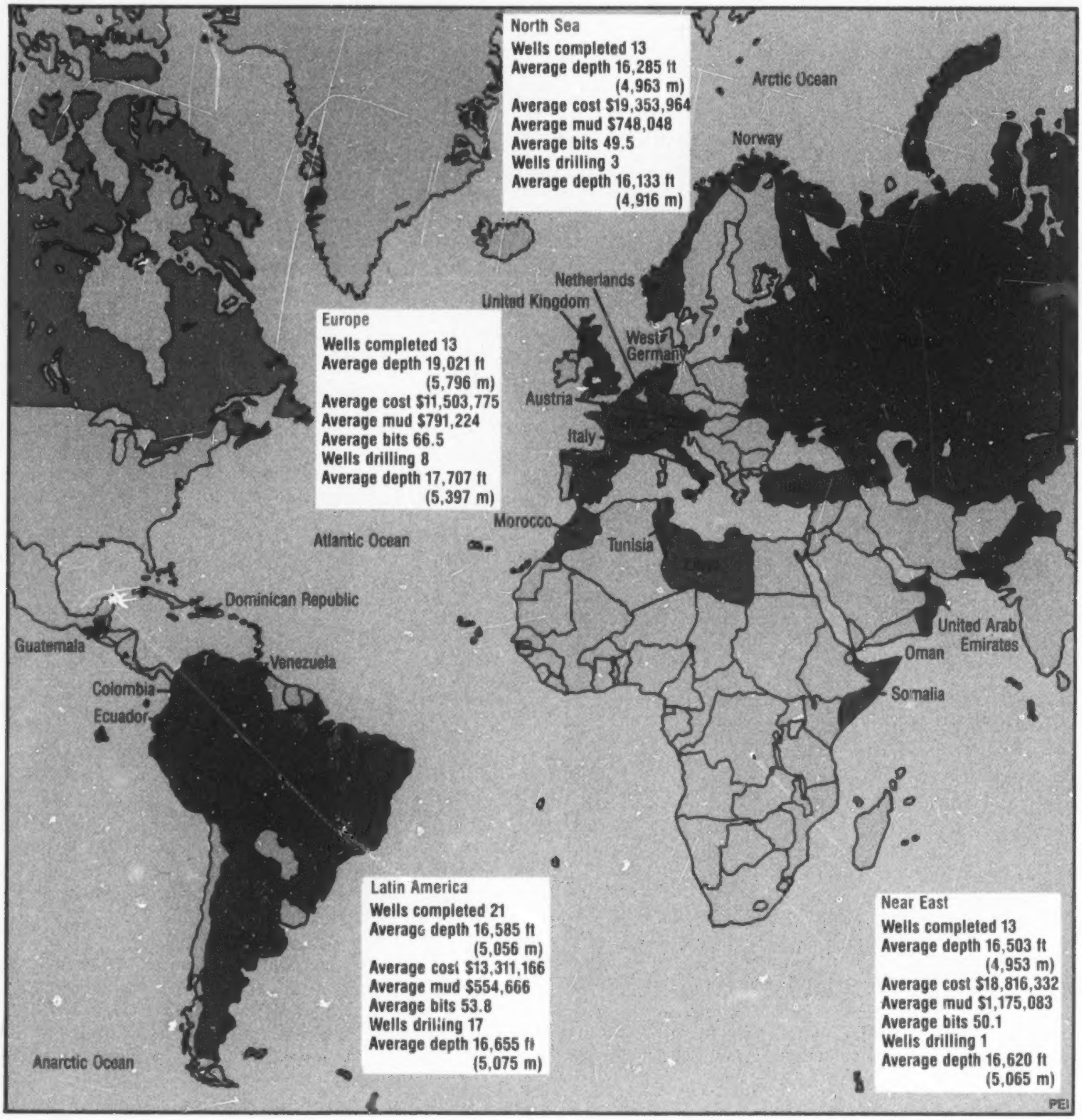
Arctic Ocean
Norway
Netherlands
United Kingdom
West Germany
Austria
Italy
Morocco
Tunisia
Libya
Atlantic Ocean
Dominican Republic
Guatemala
Venezuela
Colombia
Ecuador
United Arab Emirates
Oman
Somalia
Anarctic Ocean
PEI

North Sea
Wells completed 13
Average depth 16,285 ft (4,963 m)
Average cost $19,353,964
Average mud $748,048
Average bits 49.5
Wells drilling 3
Average depth 16,133 ft (4,916 m)

Europe
Wells completed 13
Average depth 19,021 ft (5,796 m)
Average cost $11,503,775
Average mud $791,224
Average bits 66.5
Wells drilling 8
Average depth 17,707 ft (5,397 m)

Latin America
Wells completed 21
Average depth 16,585 ft (5,056 m)
Average cost $13,311,166
Average mud $554,666
Average bits 53.8
Wells drilling 17
Average depth 16,655 ft (5,075 m)

Near East
Wells completed 13
Average depth 16,503 ft (4,953 m)
Average cost $18,816,332
Average mud $1,175,083
Average bits 50.1
Wells drilling 1
Average depth 16,620 ft (5,065 m)

obviously were seeking productive hydrocarbons. In terms of individual countries, the UK sector of the North Sea led the list, drilling nine wells at an average depth of 16,396 ft. Italy completed six at an average depth of 20,191 ft, while Venezuela and Canada drilled five each and Brazil had four to average depths of 16,187, 16,725, and 16,288 ft, respectively.

Italy Drills Deepest

The deepest wells in this year's report, excluding Eastern Europe and the Soviet Union, were the Belvedere 1 at 23,843 ft and the San Bartolomeo 4 at 23,307 ft in Italy. Both wells are located east of Milano and south of Bergamo near the Malossa field.

The Belvedere 1 was suspended, and no results were announced for the San Bartolomeo 4 well. Both wells were drilled by Agip in ENI's exclusive area in the Po Valley.

The third deepest well belonged to the Abu Dhabi Oil Co. Ltd., which drilled the JRN YAP HUR 7 to a reported depth of 21,000 ft to bring in the deepest producer in this year's report.

Since the number of deep wells per country was relatively small, cost figures were averaged on an area-wide basis to protect confidentiality. There are six areas: the North Sea, Canada, the Near East: United Arab Emirates, Libya, Morocco, Tunisia, Somalia, and Oman; the Far East: Australia, New Zealand,

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Bangladesh, Japan, and Pakistan; Europe: France, Italy, West Germany, Austria, Spain, and Turkey; and Latin America: Venezuela, Brazil, Bolivia, Colombia, Argentina, Peru, Ecuador, the Dominican Republic, and Guatemala.

Latin America Leads the Way

Latin America was the most active area, completing 21 wells at an average depth of 16,585 ft and with an average cost of $13,311,166. Mud costs were about $554,666 and average bit usage was 53.8/well.

Brazil and Venezuela were the most active countries in Latin America. Brazilian activity was offshore. Petrobras put two wells down past 15,000 ft in the Rio field in water depths of approximately 600 ft. Farther north up the coast, Hispanoil drilled the 1-ESS-44 by the province of Espirito Santo, while Petrobras completed the 1-PAS-11 to 15,354 ft southwest of the mouth of the Amazon river.

Bawden Drilling is contractor for the two rigs on the Piper platform, located in the UK sector of the North Sea, where several deep, directional wells have been drilled.

Venezuelan activity centered in the Lake Maracaibo area as well as the Machiques region. Wells averaged 16,187 ft. In addition, the country had the largest number of wells still drilling past 15,000 ft (11).

In the Near East, Abu Dhabi completed four wells at an average depth of 18,577 ft. Sources say deep drilling has increased only in the last 2 to 3 years in Abu Dhabi, spurred by interest in the Permian Khuff formation.

Well costs in the Near East averaged $18,816,332, the third highest after Canada and the North Sea. Mud costs averaged $1,175,083 and bits averaged 50.1/well. Average footage in the area was 16,503 ft for 13 wells.

Country-by-country analysis of 1982 international deep wells

Europe	**Wells completed**	**Average depth, ft**
Austria (4)*	0	0
France	2	19,573
Italy (2)	6	20,191
Spain (1)	1	17,621
Turkey (1)	0	0
West Germany	4	17,340
Latin America		
Argentina (2)	2	15,779
Bolivia	1	15,817
Brazil (3)	4	16,288
Colombia (1)	3	17,185
Ecuador	1	16.000
Guatemala	2	17,413
Peru	2	16,248
Venezuela (11)	5	16,187
Dominican Republic	1	15,952
Near East		
United Arab Emirates (1)	7	17,264
Libya	1	15,033
Morocco	1	15,846
Oman	1	15,400
Tunisia	1	15,151
Somalia	2	16,135
Far East		
Australia	3	16,766
Bangladesh	1	16,276
Japan	1	16,043
New Zealand	1	16,401
Pakistan (1)	1	16,404
North Sea		
Netherlands	1	15,856
Norway (1)	3	16,096
United Kingdom (2)	9	16,396
Canada (5)	5	16,725

*( )Wells drilling as of Jan. 1, 1983.

The North Sea and Europe each had 13 completed wells in 1982. For the North Sea, the average depth was 16,285 ft with an average cost of $19,353,964. Bit usage was a low 49.5.

Most North Sea activity centered in the northernmost portion of the UK and Norwegian sectors as operators probed the Viking Central Graben. Drilling problems included pyrites around the fringes of the northernmost play, heaving shales in almost all areas, and Zechstein salt upthrusts. In addition, pressure gradients begin rising farther south through the 40s area toward the West German sector.

European activity centers in Italy, a traditional leader in international deep drilling. Most Italian wells are located in the Po Valley between the Alps and the Pyrenees, targeting the Dolomia Principale in the Triassic at 19,686 ft. This accounts for the 19,021-ft average depth for the European wells. Well costs in the area averaged $11,503,775 and bit usage was high at 66.5/well with mud costs at $791,224.

Canadian activity was exclusively offshore Nova Scotia, Newfoundland, and Labrador with wells averaging 16,725 ft and costing approximately $67 million/well. The high cost can be attributed to the frontier area which in several cases required drillships. Also, several wells encountered hole problems as well as abnormal pressure gradients. Canadian mud costs

Worldwide
All wells drilled to 15,000 ft or deeper

Average well depth	16,957 ft	5,168 m
Average cost/well	$19,111,666	
	($1,127/ft)	($3,968/m)
Average mud cost	$852,250	
	($50/ft)	($164/m)
Average bits/well	53.3	
	(317 ft/bit)	(96 m/bit)
Success ratio	26% (72 wells)	
Wildcat success ratio	25% (55 wells)	
Development success ratio	31% (17 wells)	
Total costs: Mud	**$61,362,041**	
Drilling	**$1,216,571,874**	
Completion	**$63,392,694**	
Total costs*	**$1,376,039,983**	
Total footage	**1,220,885 ft**	
	(372,108 m)	

*Total costs throughout this report include drilling and completion costs as well as other incremental costs such as rig mobilization and demobilization.

North Sea
All wells drilled to 15,000 ft or deeper

Average well depth	16,285 ft	4,963 m
Average cost/well	$19,353,964	
	($1,188/ft)	($3,900/m)
Average mud cost/well	$748,048	
	($46/ft)	($151/m)
Average bits/well	49.5	
	(329 ft/bit)	(100 m/bit)
Success ratio	15% (13 wells)	
Wildcat success ratio	25% (4 wells)	
Development success ratio	11% (9 wells)	
Total costs: Mud	**$9,724,624**	
Drilling	**$237,013,660**	
Completion	**$3,700,000**	
Total costs	**$251,601,542**	
Total footage	**$211,711 ft**	
	(64,518 m)	

Near East
All wells drilled to 15,000 ft or deeper

Average well depth	16,503 ft	4,953 m
Average cost/well	$18,816,332	
	($1,140/ft)	($3,799/m)
Average mud cost/well	$1,175,083	
	($71/ft)	($237/m)
Average bits/well	50.1	
	(329 ft/bit)	(99 m/bit)
Success ratio	23% (13 wells)	
Wildcat success ratio	18% (11 wells)	
Development success ratio	50% (2 wells)	
Total costs: Mud	**$15,276,079**	
Drilling	**$198,871,868**	
Completion	**$19,186,672**	
Total costs	**$244,612,303**	
Total footage	**214,550 ft**	
	(64,385 m)	

Latin America
All wells drilled to 15,000 ft or deeper

Average well depth	16,585 ft	5,056 m
Average cost/well	$13,311,166	
	($802/ft)	($2,633/m)
Average mud cost/well	$554,666	
	($33/ft)	($110/m)
Average bits/well	53.8	
	(308 ft/bit)	(94 m/bit)
Success ratio	33% (21 wells)	
Wildcat success ratio	23.2% (17 wells)	
Development success ratio	75% (4 wells)	
Total costs: Mud	**$11,647,986**	
Drilling	**$264,109,999**	
Completion	**$11,570,999**	
Total costs	**$279,534,499**	
Total footage	**348,296 ft**	
	(106,155 m)	

Europe
All wells drilled to 15,000 ft or deeper

Average well depth	19,021 ft	5,796 m
Average cost/well	$11,503,775	
	($605/ft)	($1,984/m)
Average mud cost/well	$791,224	
	($42/ft)	($137/m)
Average bits/well	66.5	
	(286 ft/bit)	(88 m/bit)
Success ratio	23% (13 wells)	
Wildcat success ratio	25% (12 wells)	
Development success ratio	0% (1 well)	
Total costs: Mud	**$10,285,912**	
Drilling	**$132,661,100**	
Completion	**$2,066,300**	
Total costs	**$149,549,075**	
Total footage	**247,277 ft**	
	(75,360 m)	

Far East
All wells drilled to 15,000 ft or deeper

Average well depth	16,489 ft	5,025 m
Average cost/well	$16,194,400	
	($982/ft)	($3,223/m)
Average mud cost/well	$713,200	
	($43/ft)	($142/m)
Average bits/well	53	
	(311 ft/bit)	(95 m/bit)
Wildcat success ratio	42% (7 wells)	
Total costs: Mud	**$4,992,400**	
Drilling	**$107,368,800**	
Completion	**$1,500,000**	
Total costs	**$113,360,800**	
Total footage	**115,422 ft**	
	(35,177 m)	

averaged $1.8 million while drilling costs averaged around $55 million. Bit usage was 51/well.

In the Far East, 7 wells were completed at an average cost of $16,194,400 and an average depth of 16,489 ft. Mud costs ran $713,200/well, with each well consuming 53 bits.

Soviet Deep Drilling

Soviet deep drilling activity continues mainly as a geologic evaluation tool, although there is still activity in proven areas. The Zapadno Well 65, in the center of the Dnieper-Donets basin in the Ukraine, reached 15,696 ft, and the Trostyanetskoye Well 2, also in the Dnieper-Donets basin, reached 15,384 ft.

In the Grozny field, the Severo-Brajury was still drilling at 22,967 ft. Well 35 in Azerbaijan bordering the Caspian Sea reached a TD of 15,749 ft.

In February 1983, the Communist Party newspaper *Izvestia* reported on a 26,248-ft well in Western Siberia (Purov region) near the Urengoi gas field. Other sources, however, have that well at 26,248 ft in May 1982 with a bottomhole temperature of 150 C.

The Soviets' long-term deep drilling program also has targeted wells at locations including Nizhniy Tagil near the Ural Mountains, Krivoy Rog in the Southern

Canada
All wells drilled to 15,000 ft or deeper

Average well depth	16,725 ft	5,097 m
Average cost/well	$67,476,351	
	($4,034/ft)	($13,238/m)
Average mud cost	$1,887,008	
	($113/ft)	($370/m)
Average bits/well	51	
	(327 ft/bit)	(99 m/bit)
Wildcat success ratio	20% (5 wells)	
Total costs: Mud	**$9,435,040**	
Drilling	**$276,546,460**	
Completion	**$17,966,361**	
Total costs	**$337,381,755**	
Total footage	**83,629 ft**	
	(25,488 m)	

U.S.S.R.
All wells drilled to 15,000 ft or deeper

Wells drilled: 4*
Average depth: 17,499 ft
(5,318 m)
Average cost/well: $10,325,523
Total cost: $41,302,096

*Excludes superdeep stratigraphic wells

Average cost/meter

Depth, m	Cost/well	Cost/meter
4,500	$5,702,400	$1,267
5,000	$8,108,400	$1,622
5,500	$8,571,360	$1,558
6,000	$9,613,920	$1,602
6,500	$21,537,360	$3,313

Based on 1980 data published Nov. 15, 1982 in *Ekonomick Nefteryanoi Tromychlennoste (Economics of the Oil Industry)*. Dollars converted from rubles at $0.24/ruble.

1982 International Deep Well Contractors

Anmar Drilling
Atlantic Drilling Co. Ltd.
Atwood Oceanics Inc.
Bawden Drilling Inc.
Bow Valley Exploration Inc.
Celtic Drilling
DYVI Offshore A/S
Foramer
Forasol S.A.
Forex-Neptune
International Drilling Co.
Loffland Brothers Co.
Maersk Drilling
The Offshore Co.
ODECO Drilling
Oil Drilling & Exploration Ltd.
ONAREP
Pacnorse Drilling Corp.
Parker Drilling Co.
Penrod Drilling Co.
Perforaciones Marinas del Golfo
Rio Colorado Drilling Co.
Rowan Companies Inc.
Saipem S.p.A.
Salen Protexa Drilling Co.
Sedco Inc.
Sonpetrol
Teikoku Oil Co. Ltd.
Transocean Drilling Co. Ltd.
Westburne International Drilling Lt
Western Offshore Drilling and Exploration Co.
Zapata Off-Shore

1982 International Deep Well Operators

Abu Dhabi Marine Operating Co.
Abu Dhabi Oil Co. Ltd.
Amoco Europe Inc.
Amoco UK Ltd.
Anschutz Corp.
Arabian Gulf Oil
Agip SpA
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Statoil
Teikoku Oil Co. Ltd.
Texaco Inc.
Turkiye Petrolleri A.O.
Union Oil Co. of Great Britain
Woodside Petroleum Ltd.
Yacimientos Petroliferos Fiscales-Argentina
Yacimientos Petroliferos Fiscales Les Bolivianos

Ukraine, and Norilsk in the northwest portion of Eastern Siberia.

Average well costs are running approximately $10.3 million. This is an estimate, however, since published cost data show an 18-month lag time.

In Yugoslavia, INA-Naftaplin completed the Polyice 1 Gamma well to 18,094 ft and had at least two other wells drilling past 18,000 ft.

As for the future of international deep drilling, it seems safe to say that the level of activity should tend to increase over the years for much the same reason it has increased in the U.S. As shallow reserves are depleted, operators will be forced to go deeper for reserve additions.

This report was compiled from raw well data courtesy of Oil Resource Corp. of Houston representing Petro-Consultants Inc. of Geneva, Switzerland. Operators supplied cost data on a confidential basis. The author wishes to thank Patricia Gallik and Joe Summa of Oil Resource Corp. for their assistance. Special thanks also go to Dr. Harry Walsh and Catherine Cauvin-Higgins at the University of Houston. ■

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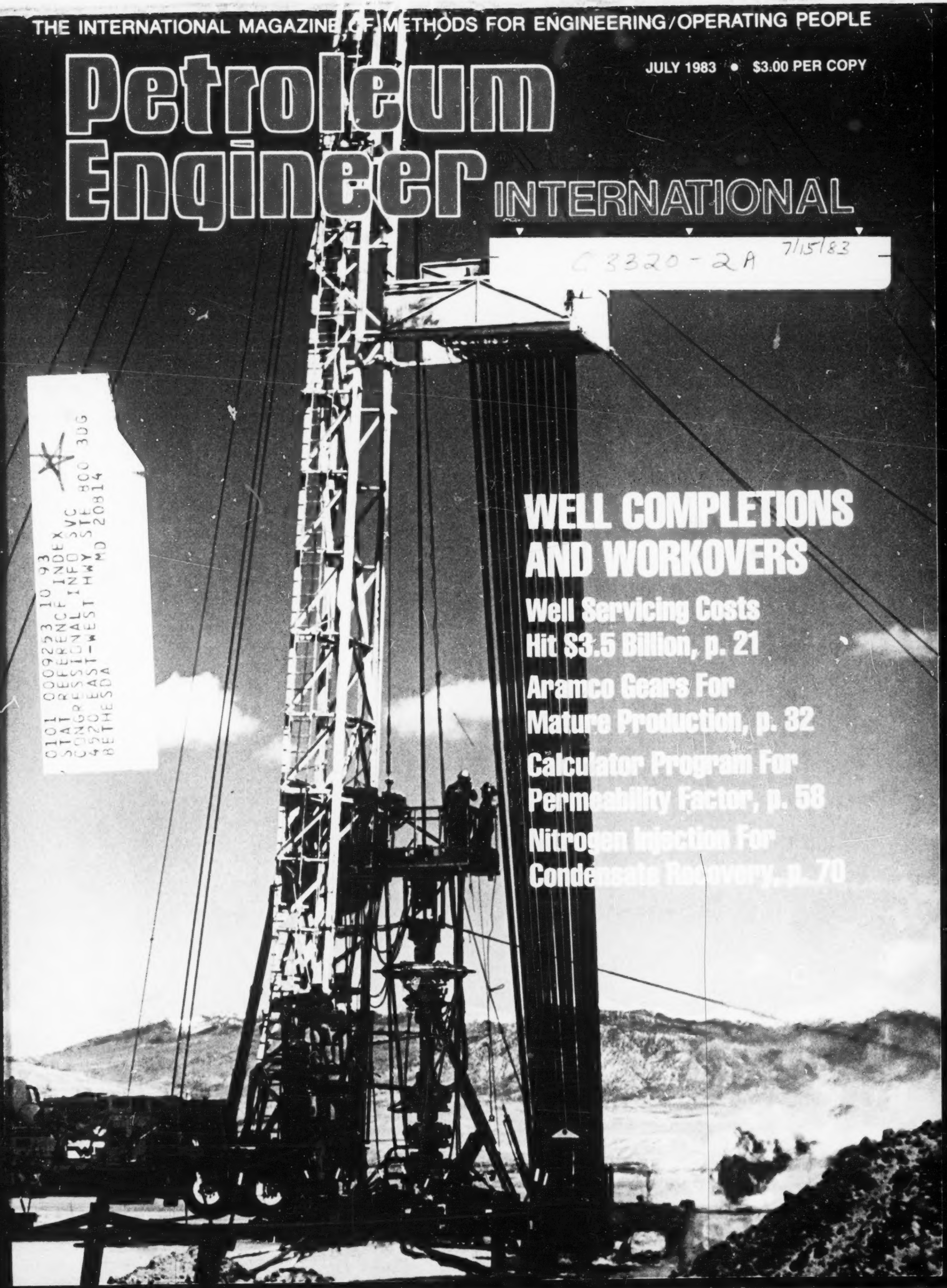

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WELL COMPLETIONS AND WORKOVERS

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ABOUT THE COVER: With the aid of injected nitrogen, a permanent packer is drilled out of a live well in Wyoming's Wind River Basin. Operator is Tom Brown Inc. (Photo by Cudd Pressure Control.)

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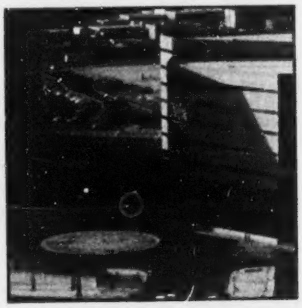

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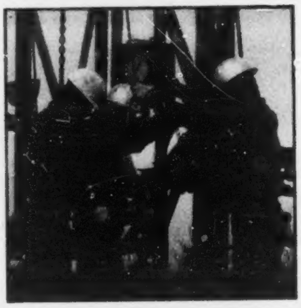

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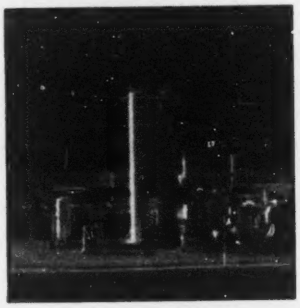

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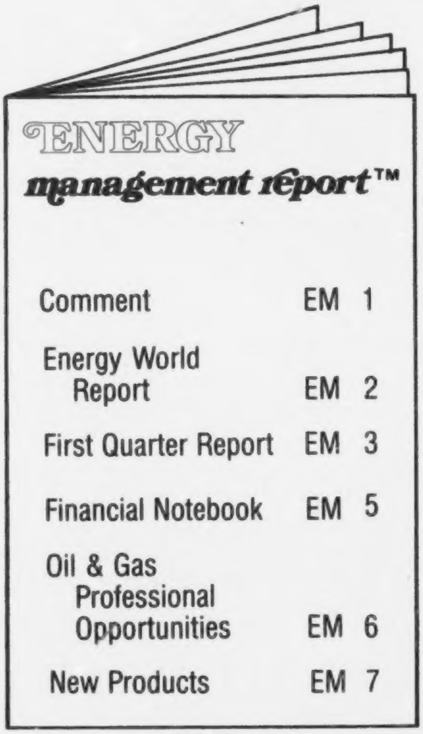

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Engineering Profits into Energy Operations

Drillers Survive Spring Slump

Although the U.S. rotary rig count apparently is returning to its traditional pattern of declining from year-end peak to spring low, it seems to be doing it with a vengeance this year. Rigs running during the first five months of 1983 dropped by about 30%, compared with the normal decline of about 12%.

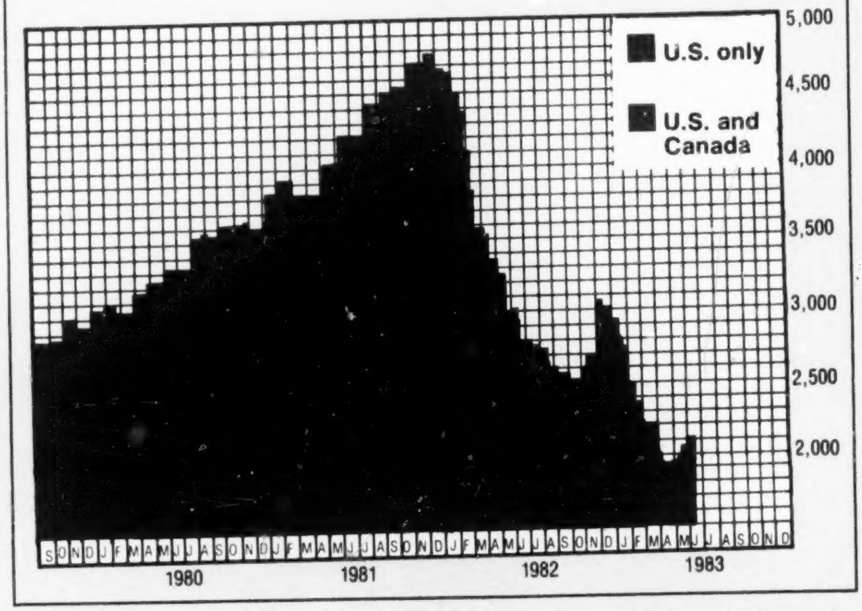
Nevertheless, indications are that the long slump has at least bottomed out. The average rig count so far this year (as of early last month) is 2,124, and Hughes Tool Co., compiler of the weekly count, is projecting an average count of 2,285 for the year. Last year's average rig count was 3,105.

Canadian drillers seem to be coming out of their spring slump, also, with their rig count gaining more than 100 rigs from early May to early June.

Rotary rigs actually making hole in United States & Canada

As Reported To International Association Of Drilling Contractors By Hughes Tool Co.

	May 16, 1983	May 23, 1983	May 30, 1983	June 6, 1983
Alabama				
Land	11	11	10	10
Inland Waters	3	3	3	3
Offshore	1	1	1	1
Alaksa				
Land	10	10	9	9
Offshore	6	6	5	5
Total	16	16	14	14
Arkansas	25	25	25	21
California				
Land	70	73	78	76
Offshore	21	22	25	25
Total	91	95	103	101
Colorado	42	45	41	47
Florida	5	4	5	5
Hawaii	1	1	1	1
Idaho	1	0	0	0
Illinois	59	62	59	73
Indiana	7	6	8	6
Kansas	109	116	115	115
Kentucky	7	7	7	11
North Louisiana	26	24	20	20
South Louisiana				
Inland Waters	41	41	42	45
Land	61	67	63	66
Offshore	121	122	126	129
Total	249	254	251	260
Michigan	19	21	23	22
Mississippi	26	27	23	23
Montana	15	15	15	22
Nebraska	13	11	7	5
Nevada	1	1	1	1
New Mexico	59	66	61	54
New York	6	11	14	17
North Carolina	—	1	1	1
North Dakota	29	30	30	38
Ohio	22	23	20	20
Oklahoma	270	253	243	247
Pennsylvania	8	12	13	13
Texas				
Offshore	55	60	55	52
Inland Waters	7	6	7	8
Dist. 1-S. Central Tex.	22	20	18	20
Dist. 2-Middle Tex. Coast	24	20	22	26
Dist. 3-Upper Tex. Coast	99	100	85	86
Dist. 4-Lower Tex. Coast	43	54	66	67
Dist. 5-Northeast Tex.	23	25	25	26
Dist. 6-Far Northeast Tex.	75	74	66	63
Dist. 7B-N. Central Tex.	63	50	57	54
Dist. 7C-W. Central Tex.	54	53	44	44
Dist. 8-Far West Tex.	89	91	83	86
Dist. 8A-West Tex.	55	52	56	64
Dist. 9-North Tex.	55	51	52	56
Dist. 10-Tex. Panhandle	46	45	47	48
Total	710	701	683	700
Utah	32	30	32	30
Virginia	1	1	1	1
Washington	1	1	1	1
West Virginia	27	37	28	32
Wyoming	58	59	60	64
Total U.S.	1,924	1.946	1,899	1,959
Canada	73	78	108	140
Canada-Offshore	6	7	7	8
U.S. and Canada	2,003	2,031	2,014	2,108



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Well Servicing Costs Hit $3.5 Billion

by Steven D. Moore, *Drilling Editor*

Although well servicing expenditures for 1982 didn't reach 1981's record level, totals are still impressive. In fact, with the exception of 1981, operators spent more money for well servicing in 1982 than in any other year.

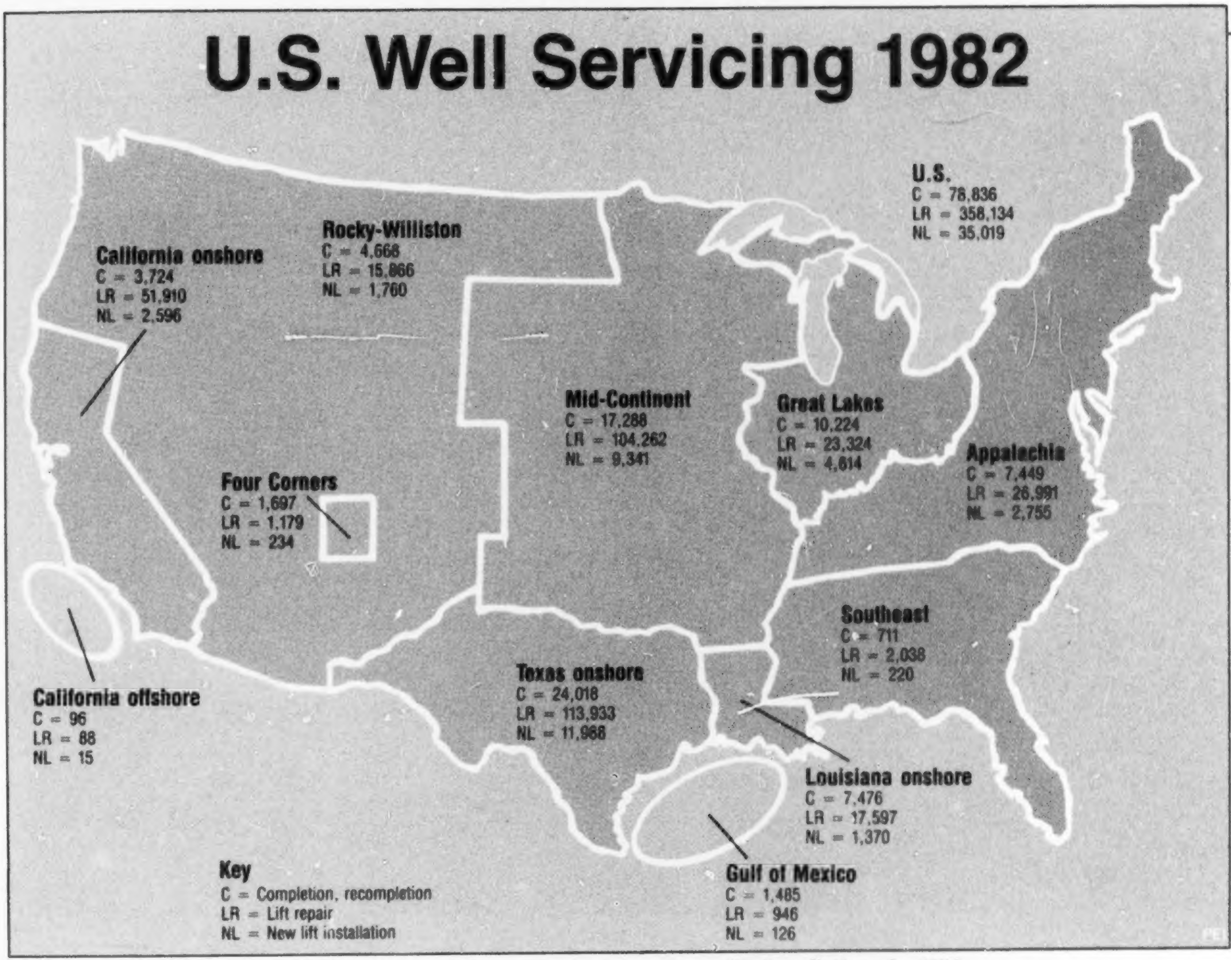
Results from PETROLEUM ENGINEER INTERNATIONAL's exclusive well servicing survey found that 1982 expenditures dropped some 12% from the $4.013 billion spent in 1981. In all, operators spent more than $3.5 billion to service and workover 834,872 U.S. oil and gas wells. The projected well servicing budget for 1983 is slightly more than $3.6 billion.

Even though operators are budgeting more for well servicing in 1983 doesn't mean they will spend it. In response to last year's survey, operators projected a total well servicing budget of $4.5 billion, but ended up spending only 78% of that money. Certainly 1982 was a unique year, but chances are operators won't spend their entire budgets this year either, particularly with the natural gas bubble.

Don't be surprised if operators spend only 80% to 85% of their estimated budgets this year, which would come to roughly $3 billion. If so, total well servicing expenditures will be about the same as they were for 1979 and 1980. But considering that rabid oil field inflation persisted during the interim and that total U.S. well population grew by approximately 100,000 wells between the end of 1980 and the beginning of 1983, operators will require less service work per well than in previous years.

With the downturn in the oil business last year, it's not surprising to find expenditures off in 1982. As crude oil prices declined and an oversupply of natural gas developed, drilling and well servicing activities tapered off. The big push to rejuvenate shut-in and abandoned wells that swept the industry in 1980 and 1981 was no longer there. In addition, many marginal wells brought on production in 1981 became uneconomical to produce in the latter half of 1982 as oil prices slumped.

From responses of over 200 operating companies, both majors and independents, PEI puts together an annual well servicing survey to monitor past activity, as well as future budget estimates. This year's survey is broken down into 11 different geographic regions. Tables 1, 2, and 4 are tabulations of completion, workover, and servicing totals for 1982; tables 5 through 15 summarize regional well servicing activity.


U.S. Well Servicing 1982
U.S.
C = 78,836
LR = 358,134
NL = 35,019
California onshore
C = 3,724
LR = 51,910
NL = 2,596
Rocky-Williston
C = 4,668
LR = 15,866
NL = 1,760
Mid-Continent
C = 17,288
LR = 104,262
NL = 9,341
Great Lakes
C = 10,224
LR = 23,324
NL = 4,614
Appalachia
C = 7,449
LR = 26,991
NL = 2,755
Four Corners
C = 1,697
LR = 1,179
NL = 234
Southeast
C = 711
LR = 2,038
NL = 220
California offshore
C = 96
LR = 88
NL = 15
Texas onshore
C = 24,018
LR = 113,933
NL = 11,968
Louisiana onshore
C = 7,476
LR = 17,597
NL = 1,370
Key
C = Completion, recompletion
LR = Lift repair
NL = New lift installation
Gulf of Mexico
C = 1,485
LR = 946
NL = 126

Breakdown by regions of completions-recompletions, lift repairs, and new lift installations for 1982.

Downturn In Spending

Of all the regions, Texas once again led in well servicing expenditures. Texas operators spent $1.147 billion in 1982 compared with $1.228 billion the previous year. Nearly one-third of the money spent on well servicing in the U.S. last year was spent in Texas. The trend should continue this year as the estimated cumulative budget for Texas exceeds $1.2 billion. Average servicing costs for a typical Texas well were down slightly from previous years to $4,351, compared with $4,935 and $4,840 in 1981 and 1980, respectively.

The Mid-Continent again was second to Texas in well servicing expenditures – the $681 million spent by operators in the area was approximately 19% of the total U.S. well servicing costs. Expenditures were off 4% from the $712 million spent in 1981, but the area's expected budget for 1983 is in the $716 million range. Servicing costs for the average Mid-Continent well slipped to $3,486 in 1982 from $3,861 the previous year.

The Gulf of Mexico continues to be the most expensive region in which to service wells. In fact, the $418 million spent last year in the area is nearly a 13% increase over 1981, when operators spent $370 million. In 1982 operators paid close to $42,000 per well for servicing. Of the onshore areas, the Rocky Mountains were the most expensive region for servicing work – typical servicing costs per well were about $12,400.

On the opposite end of the spectrum is the Appalachia region where operators spent an average $1,131 per well for well servicing, approximately half of what was spent on a well in the area in 1981. Decreased spending in the area reflects a reversing trend away from what happened in 1980 and 1981 when shut-in and marginal producing wells were commonly serviced. In addition, many producers who operate 500-ft deep wells opt to drill a new well instead of servicing an old well. Because of similar circumstances, the Great Lakes area also showed a significant drop in spending.

Over 50% of all 1982 U.S. well servicing expenditures were the accumulated totals of Texas and Mid-Continent. On a national average, the typical U.S. well required $4,232 in servicing – approximately 17% less than the $5,081 per well spent in 1981.

Well Population Climbs

Surprisingly, the number of completions and recompletions in 1982 exceeded 1981's record total by about 2% – completions and recompletions climbed from 77,457 in 1981 to 78,836 in 1982. Rig activity did not reflect this increase, but in part the rise was due to the lag time in reporting completions, as well as recompletions. Operators completed 56,204 wells last year, up from 55,167 wells in 1981. Development wells continue to outpace exploration wells 10 to 1.

Oil well completions dropped from a record high of

38,995 wells in 1981 to 37,821 wells last year. Still, oil well completions were way ahead of the 26,901 wells completed in 1980. Gas well completions showed a 12% increase last year over 1981, totaling 18,383 well completions compared with 16,172 wells in 1981. The number of recompletions increased to 22,632 wells.

The U.S. well population continues to climb at a steady pace – in fact, the number of producing wells increased for the eighth straight year. At the end of 1982, 834,872 wells were on stream, with 621,690 wells producing oil. In all, the number of producing wells climbed 6% over 1981. Well abandonments showed a slight increase from 10,452 wells in 1981 to 11,157 wells.

Total wells on artificial lift reached an all-time high of 577,261 wells in 1982, a 3.5% increase over the previous year. Approximately 93% of all U.S. oil wells are on some form of artificial lift.

Texas and the Mid-Continent led the way with a combined total of more than 41,000 completions and recompletions. Texas producers completed or recompleted 24,018 wells last year, a 2% increase over 1981. Conversely, Mid-Continent operators completed or recompleted 17,288 wells last year compared with 19,203 in 1981, a 10% drop.

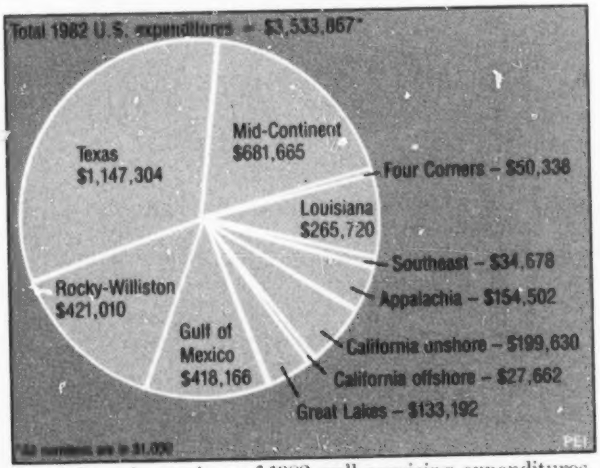
Tubular Repairs

Little change was denoted in the number of tubular repairs from 1981 to 1982. With the well servicing rig utilization rate down last year, one would not expect as many repairs as in 1981, but, again, lag time in reporting may have influenced these numbers. Furthermore, with the shortage of rigs, tubular goods, and equipment throughout 1981, many operators carried over needed repair work into 1982.

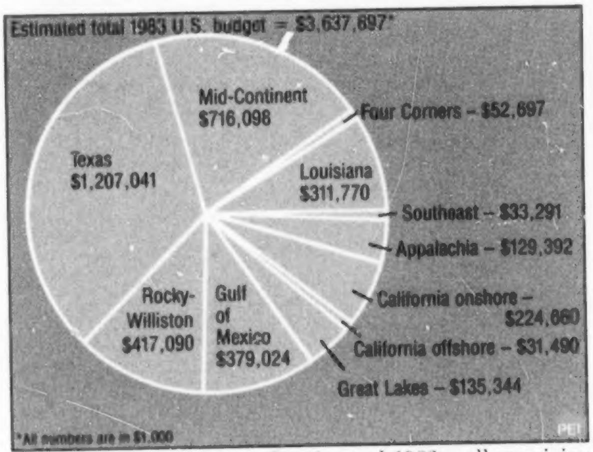
Tubular repairs totaled 68,599 for 1982, with tubing repairs outpacing casing repairs 8 to 1. Areas with the most activity were Texas, the Mid-Continent, and the Great Lakes. Table 3 gives a complete breakdown of tubing and casing repairs.

Stimulation

Acid and frac stimulation jobs for remedial work in 1982 were on par with 1981 – about 33,000 jobs each year. Actual numbers are probably higher, but some operators simply budget money for a particular field and do not record the total number of wells stimulated. Most active areas for stimulation work were Texas, the Mid-Continent, the Rockies, onshore California, and the Great Lakes. Fracturing tapered off due to the oversupply of natural gas – the operators did not have the price incentives to fracture tight gas reservoirs or deep gas pay zones, as in previous years.



Breakdown by regions of 1982 well servicing expenditures.



Breakdown by regions of estimated 1983 well servicing budgets.

Rod Pumping

As U.S. oil production matures, artificial lift will play a more important role. Of the oil wells on artificial lift, more than 85% use conventional rod pumping units. Over 32,000 wells were equipped with rod pumps last year, about the same as in 1981.

Meanwhile, the shortage of sucker rods in 1981 quickly turned into a surplus in 1982. It's nearly impossible to estimate total footage of sucker rods sold last year, because so many people were selling them. As 1982 wore on, manufacturers found their biggest competition coming from their own customers who needed to reduce inventories.

In addition, used rods made a comeback last year. When well servicing costs are high, operators will not take a chance on used rods, so they simply buy new ones. Now, with well servicing costs down, operators are willing to take the risk of buying used rods.

In many cases, so-called used rods are practically new. During the 1981 boom, promoters cut deals with investors for wells that could barely make a couple of barrels per day. Now many of these wells are abandoned and the rods, with little wear and tear, are available.

Also, pumping units and sucker rods are being moved from well to well these days – from low- to high-volume producers, within the capacity of the pumping unit. Operators are doing this to maintain as much production as possible without working over their low-volume wells. In other words, some operators are choosing to leave a 10-b/d well off production if the equipment can be moved to a better well.

Although this puts a real crunch on suppliers and manufacturers, well servicing contractors are keeping fairly busy, because, even though they are not servicing

TABLE 1. Completion, workover, servicing summary, by region, 1982

Region	Total wells	Completion, recompletion	Total art. lift	Lift repair	New lift installation	Tubular repair	Frac/acid stimulate	Total budget, $M
U.S.(1)	834,872	78.836	577,261	358,134	35,019	68,599	32,760	3,533,867
Appalachia	136,502	7,449	68,824	26,991	2,755	8.045	391	154,502
California onshore	50,428	3,724	46,426	51,910	2,596	5,203	2,828	199,630
California offshore	1,727	96	1,607	88	15	324	33	27,662
Four Corners	15,405	1,697	2,081	1,179	234	280	250	50,338
Great Lakes	83,635	10,224	60,621	23,324	4,614	13,199	2,525	133,192
Gulf of Mexico	9,729	1,485	834	946	126	434	466	418,166
Louisiana onshore	39,331	7,476	21,839	17,597	1,370	2,841	1,988	265,720
Mid-Continent (2)	195,533	17,288	158,465	104,262	9,341	16,726	8,745	681,665
Rocky-Williston	34,035	4,668	22,400	15,866	1,760	3,180	2,785	421,010
Southeast	4,898	711	3,165	2,038	220	707	231	34,678
Texas onshore (3)	263,649	24,018	190,999	113,933	11,988	17,660	12,518	1,147,304

(1) Excludes Alaska
(2) Includes Texas Panhandle
(3) Includes southeast New Mexico: excludes Texas Panhandle

TABLE 2. Completions and recompletions, by region

	Wells Jan. 1, 1983		Exploration		Development		Recompletions		
	Oil	Gas	Oil	Gas	Oil	Gas	Same zone	New zone	Abandons
U.S.(1)	621,690	213,182	2,235	2,385	35,586	15,998	12,484	10,148	11,157
Appalachia	70,448	66,054	170	654	2,587	3,234	658	146	1,373
California onshore	49,291	1,137	96	58	2,380	88	751	351	710
California offshore	1,727	—	7	—	61	—	25	3	4
Four Corners	2,259	13,146	42	112	249	1,029	163	102	113
Great Lakes	61,544	22,091	264	90	4,439	3,000	1,262	1,169	2,011
Gulf of Mexico	5,513	4,216	23	56	154	283	354	615	83
Louisiana	25,724	13,607	36	66	1,558	1,550	2,035	2,231	879
Mid-Continent(2)	160,457	35,076	431	215	9,424	2,764	1,874	2,580	1,902
Rocky-Williston	26,041	7.994	387	178	1.606	703	1,151	643	809
Southeast	3,801	1,097	35	24	208	129	115	200	54
Texas onshore(3)	214,885	48,764	744	932	12,920	3,218	3.219	4,096	3,219

(1) Excludes Alaska
(2) Includes Texas Panhandle
(3) Includes southeast New Mexico: excludes Texas Panhandle

TABLE 3. Tubular goods repair, by region

	Casing					Tubing				
	1978	1979	1980	1981	1982	1978	1979	1980	1981	1982
U.S.	6,631	3,772	6,566	8,778	7,898	24,615	62,946	49,598	58,198	60,701
Appalachia	—	—	926	1,056	1.025	—	—	4,783	5,252	7,020
California onshore	1,424	71	302	237	365	1,505	1,256	3,285	3.874	4,838
California offshore	—	—	14	9	28	—	60	67	192	296
Four Corners	—	85	32	22	83	—	505	129	51	197
Great Lakes	—	300	609	39	374	—	4,500	4,657	11,907	12,825
Gulf of Mexico	23	—	30	16	102	24	182	208	178	332
Louisiana onshore	211	180	189	953	446	1,631	1,513	1,451	4,578	2,395
Mid-Continent	1,381	1,400	1,944	1,243	1,537	11,055	25,202	13.145	16,270	15,189
Rocky-Williston	297	431	377	2,501	642	471	1,255	1,636	1,673	2,538
Southeast	—	42	46	404	77	—	357	391	445	630
Texas onshore	3,295	1,263	2,097	2,298	3,219	9,929	28,116	19,846	13,778	14,441

these low-volume wells, they are pulling the rods from one well and running them in another.

Overall, rod pump and sucker rod repair last year was off from 1981 levels. Rod pump repairs came close to the previous year, 207,000 jobs compared with 216,000 in 1981, but sucker rod work dropped significantly from 199,000 to 130,000 jobs. Partly the decline in sucker rod work was due to all the new sucker rods put into wells during the two previous years. Historically rod pump repairs outnumber sucker rod jobs about 2 to 1, so after 2 years of an abnormally high percentage of sucker rod jobs, the industry has returned to a more traditional ratio.

Other Artificial Lifts

Installation of other forms of artificial lift dipped last year compared with the previous year. With pump jacks practically being given away during the last 2 years, the trend is not too surprising. Operators brought more than 2,600 wells on production using either electric submersible pumps, hydraulic pumps, or gas lift.

Of the three types of lifts, electric submersible pumps were installed in the most wells. With increasing water cuts in many producing wells, higher pump capacity is needed to produce the same amount of oil,

TABLE 4. Total U.S. service jobs in 1982

Abandoned (old wells)	11,157
Recompletions – same reservoir	12,484
Recompletions – different reservoir	10,148
Stimulation – acid or frac	32,760
Tubing repair or replacement	60,701
Casing repair	7,898
Rod pump repair	207,2[illegible]3
Sucker rod work	129,825
New rod pump installation	32,338
Submersible pump repair	7,840
New submersible pump installation	1,380
Hydraulic pump repair	7,639
New hydraulic pump installation	327
Gas lift repair	5,537
New gas lift installation	974

TABLE 5. Appalachia service jobs in 1982

Abandoned (old wells)	1,373
Recompletions – same reservoir	658
Recompletions – different reservoir	146
Stimulation – acid or frac	391
Tubing repair or replacement	7,020
Casing repair	1,025
Rod pump repair	17,679
Sucker rod work	9,312
New rod pump installation	2,755
Submersible pump repair	—
New submersible pump installation	—
Hydraulic pump repair	—
New hydraulic pump installation	—
Gas lift repair	—
New gas lift installation	—

TABLE 6. California onshore service jobs in 1982

Abandoned (old wells)	710
Recompletions – same reservoir	751
Recompletions – different reservoir	351
Stimulation – acid or frac	2,828
Tubing repair or replacement	4,838
Casing repair	365
Rod pump repair	31,542
Sucker rod work	17,288
New rod pump installation	2,339
Submersible pump repair	963
New submersible pump installation	122
Hydraulic pump repair	1,656
New hydraulic pump installation	43
Gas lift repair	361
New gas lift installation	92

TABLE 7. California offshore service jobs in 1982

Abandoned (old wells)	4
Recompletions – same reservoir	25
Recompletions – different reservoir	3
Stimulation – acid or frac	33
Tubing repair or replacement	296
Casing repair	28
Rod pump repair	—
Sucker rod work	—
New rod pump installation	—
Submersible pump repair	58
New submersible pump installation	13
Hydraulic pump repair	—
New hydraulic pump installation	—
Gas lift repair	30
New gas lift installation	2

TABLE 8. Four Corners service jobs in 1982

Abandoned (old wells)	113
Recompletions – same reservoir	163
Recompletions – different reservoir	102
Stimulation – acid or frac	250
Tubing repair or replacement	197
Casing repair	83
Rod pump repair	784
Sucker rod work	348
New rod pump installation	229
Submersible pump repair	47
New submersible pump installation	5
Hydraulic pump repair	—
New hydraulic pump installation	—
Gas lift repair	—
New gas lift installation	—

TABLE 9. Great Lakes service jobs in 1981

Abandoned (old wells)	2,011
Recompletions – same reservoir	1,262
Recompletions – different reservoir	1,169
Stimulation – acid or frac	2,525
Tubing repair or replacement	12,825
Casing repair	374
Rod pump repair	15,683
Sucker rod work	7,528
New rod pump installation	4,603
Submersible pump repair	113
New submersible pump installation	11
Hydraulic pump repair	—
New hydraulic pump installation	—
Gas lift repair	—
New gas lift installation	—

TABLE 10. Gulf of Mexico (offshore only) service jobs in 1982

Abandoned (old wells)	83
Recompletions – same reservoir	354
Recompletions – different reservoir	615
Stimulation – acid or frac	466
Tubing repair or replacement	332
Casing repair	102
Rod pump repair	—
Sucker rod work	—
New rod pump installation	—
Submersible pump repair	52
New submersible pump installation	5
Hydraulic pump repair	—
New hydraulic pump installation	—
Gas lift repair	894
New gas lift installation	121

TABLE 11. Louisiana onshore service jobs in 1982

Abandoned (old wells)	879
Recompletions – same reservoir	2,035
Recompletions – different reservoir	2,231
Stimulation – acid or frac	1,988
Tubing repair or replacement	2,395
Casing repair	446
Rod pump repair	9,802
Sucker rod work	5,403
New rod pump installation	1,065
Submersible pump repair	432
New submersible pump installation	178
Hydraulic pump repair	1,525
New hydraulic pump installation	48
Gas lift repair	435
New gas lift installation	79

(Continued)

TABLE 12. Mid-Continent service jobs in 1982

Abandoned (old wells)	1,902
Recompletions – same reservoir	1,874
Recompletions – different reservoir	2,580
Stimulation – acid or frac	8,745
Tubing repair or replacement	15,189
Casing repair	1,537
Rod pump repair	58,117
Sucker rod work	40,718
New rod pump installation	8,676
Submersible pump repair	2,889
New submersible pump installation	431
Hydraulic pump repair	1,499
New hydraulic pump installation	54
Gas lift repair	1,039
New gas lift installation	180

TABLE 13. Rocky Mountains – Williston Basin service jobs in 1982

Abandoned (old wells)	809
Recompletions – same reservoir	1,151
Recompletions – different reservoir	643
Stimulation – acid or frac	2,785
Tubing repair or replacement	2,538
Casing repair	642
Rod pump repair	7,230
Sucker rod work	6,508
New rod pump installation	1,452
Submersible pump repair	1,247
New submersible pump installation	151
Hydraulic pump repair	767
New hydraulic pump installation	117
Gas lift repair	114
New gas lift installation	40

TABLE 14. Southeast service jobs in 1982

Abandoned (old wells)	54
Recompletions – same reservoir	115
Recompletions – different reservoir	200
Stimulation – acid or frac	231
Tubing repair or replacement	630
Casing repair	77
Rod pump repair	1,177
Sucker rod work	719
New rod pump installation	198
Submersible pump repair	49
New submersible pump installation	17
Hydraulic pump repair	30
New hydraulic pump installation	5
Gas lift repair	63
New gas lift installation	—

TABLE 15. Texas onshore service jobs in 1982

Abandoned (old wells)	3,219
Recompletions – same reservoir	4,096
Recompletions – different reservoir	2,108
Stimulation – acid or frac	12,518
Tubing repair or replacement	14,441
Casing repair	3,219
Rod pump repair	65,179
Sucker rod work	42,001
New rod pump installation	11,021
Submersible pump repair	1,990
New submersible pump installation	447
Hydraulic pump repair	2,162
New hydraulic pump installation	60
Gas lift repair	2,601
New gas lift installation	460

so the trend toward electric submersibles should continue.

The four most popular areas for electric submersible pumps are Louisiana, Texas, the Mid-Continent, and the Rockies. Average operating time between failures is approximately 1¼ to 1½ years. Operating life is about twice as long in the Mid-Continent than in Texas because of lower pressures and temperatures and less corrosion. One operator in California averages nearly 2 years between failures.

Hydraulic pumps captured only about 1% of the artificial lift market last year. Operators in several regions installed hydraulic pumps, but the most active area was the Rockies, where many of the installations were in isolated wells without access to electricity.

Gas lift installations have fallen over the past few years. The downturn is a mixture of several changing market forces. First, even though an oversupply of natural gas exists, the cost of gas has risen sharply over the years; natural gas for gas lift is affordable in only a few select areas, predominantly offshore. Second, the cost of compressors and other surface equipment create high front-end expenses. And third, with increasing water cuts in most U.S. oil wells, the amount of gas needed to produce a barrel of oil is increasing.

Servicing Outlook

The well servicing contractor is facing the same predicament as the drilling contractor – an oversupply of rigs which has forced both drilling and servicing rig utilization rates below 50%. In addition, the prudent well servicing contractor is being squeezed at both ends of his market.

One problem is competition with the contractor who readily bids suicide rates to stave off bankruptcy. The situation is improving somewhat as some of these contractors go out of business and more operators are willing to accept reasonable bids in exchange for quality work.

He also must compete with drilling contractors who have entered the completion and 24-hr servicing market. Many drilling contractors are offering their rigs for practically nothing to keep them on location for completion of the well and to keep their rig crews busy. Drilling contractors are not expected to leave this market until their own industry turns around.

The outlook for the well servicing industry is not overly optimistic, but if the well servicing rig utilization rate has bottomed out, some of the industry's uncertainty about the future will be abated. Then contractors, service and supply companies, and manufacturers can all start planning for better times ahead.

Acknowledgement. Data presented were based on PETROLEUM ENGINEER INTERNATIONAL's 1982 well servicing survey. Responses came from more than 200 independent and integrated companies. Appropriate data base used for projections was corroborated with data published by API and Petroleum Information Corp. PEI also thanks Baker Oil Tools for helping to distribute surveys. ■

Oversupplies dampen profit picture

An oversupply of crude oil and of refined products was primarily responsible for the drop in earnings in the oil industry during the first quarter of 1983.

While the refining and marketing sectors of most companies lost money, the profit picture was also dampened by unusually warm weather and the recession, reducing demand and lowering prices.

The 99 companies responding to our survey report net income of $4.2 billion, a 16.6% drop from the previous year. Profit margin for the group fell from 3.9% to 3.6%.

Gains in crude oil, condensate, and natural gas production were more than offset by significantly reduced refining and marketing earnings and higher year-to losses in metals at Atlantic Richfield. Net income fell 14% during the first quarter.

Exxon posted a 26% increase in income for the quarter, earning $839 million in 1982 and $1.06 billion in 1983.

Disappointing results in refining, marketing, and chemicals operations due to an intensely competitive market are blamed for Gulf Oil's 37% decline in net earnings. The company faults companies with large quantities of low-cost Alaskan oil for forcing down gasoline prices in the U.S.

Mobil Corp. reported a 32% drop in earnings for the first quarter, falling from $369 million in 1982 to $250 million in 1983.

Increased interest charges resulting from the Cities Service acquisition adversely affected Occidental Petroleum's earnings picture. Net income in the first quarter 1982 was $61.1 million compared to $25.9 million this year.

A $38.6 million settlement from FERC more than offset the effect of sharply curtailed natural gas sales at Pennzoil. Earnings increased from $38.9 million in 1982 to $40.3 million in 1983.

Standard Oil of California's 35% earnings increase resulted mainly from the lower cost of crude oil,

GAS COMPANIES' FIRST QUARTER FINANCIAL REPORTS

	Three months ending March 31**							
	Revenues ($000)			Earnings* ($000)			Profit Margin‡	
Company	1983	1982	% Chg.	1983	1982	% Chg.	1983	1982
Alabama Tennessee N.G.	43,240	37,273	+ 16.0	1,643	1,671	- 1.7	3.8	4.5
American Nat. Resources	982,500	1,063,300	- 7.6	60,900	79,900	- 23.8	6.2	7.5
ARKLA	410,450	398,729	+ 2.9	32,741	45,781	- 28.5	8.0	11.5
Coastal Corp.	1,562,136	1,565,505	- 0.2	14,063	6,002	+134.3	0.9	0.4
Columbia Gas	1,756,506	1,875,546	- 6.3	67,677	93,455	- 27.6	3.9	5.0
Consolidated Nat. Gas	1,217,102	1,200,451	+ 1.4	70,179	87,695	- 20.0	5.8	7.3
El Paso Companies	1,222,838	1,055,581	+ 15.9	14,290	21,192	- 32.6	1.2	2.0
ENSERCH Corp.	991,561	1,004,460	- 1.3	43,516	59,495	- 26.9	4.4	5.9
Houston N.G.[1]	696,727	785,162	- 11.3	47,697	63,511	- 24.9	6.8	8.1
InterNorth	1,359,742	1,449,253	- 6.2	101,513	106,144	- 4.4	7.5	7.3
Mountain Fuel Supply	203,708	182,042	+ 11.9	26,457	22,479	+ 17.7	13.0	12.4
National Fuel Gas	402,991	398,741	+ 1.1	18,282	25,027	- 27.0	4.5	6.3
Northwest Energy	803,542	486,945	+ 65.0	32,577	32,564		4.1	6.7
NOVA, An Alberta Corp.	1,067,000	730,000	+ 46.2	32,500	27,400	+ 18.6	3.1	3.8
ONEOK Inc.[2]	349,072	378,689	- 7.8	22,184	30,539	- 27.4	6.4	8.1
Pacific Lighting	1,267,059	1,174,430	+ 7.9	32,507	28,757	+ 13.0	2.6	2.4
Panhandle Eastern	1,034,329	956,671	+ 8.1	61,568	73,361	- 16.1	6.0	7.7
Peoples Energy	593,963	702,009	- 15.3	34,013	40,536	- 16.0	5.7	5.7
Pioneer Corp.	288,665	302,413	- 4.5	21,517	29,843	- 27.9	7.5	9.9
Sonat Inc.	846,192	815,673	+ 3.7	65,605	63,199	+ 3.8	7.8	7.7
Southern Union Co.	345,810	344,494	+ 0.4	13,879	13,040	+ 6.4	4.0	3.8
Texas Eastern Corp.	1,459,441	1,424,588	+ 2.4	37,650	61,925	- 39.2	2.6	4.3
Texas Gas Transmission	791,556	783,264	+ 1.1	24,766	29,791	- 16.9	3.1	3.8
TransCanda PipeLines	923,493	1,020,555	- 9.5	46,423	38,724	+ 19.9	5.0	3.8
Transco Energy Co.	1,166,626	916,659	+ 27.3	36,785	36,062	+ 2.0	3.2	3.9
United Energy Resources	1,259,819	1,574,863	- 20.0	39,659	64,197	- 38.2	3.1	4.1
Westcoast Transmission	331,930	424,274	- 21.8	17,173	19,534	12.1	5.2	4.6
TOTAL	23,377,998	23,051,570	+ 1.4	1,017,764	1,201,824	- 15.3	4.4	5.2

*Earnings available to common. **Excluding non-recurring items. ‡Earnings* divided by Revenues.
[1] Ends April 30. [2] Ends February 28.

reduced exploration expenses, and some firming of petroleum product prices toward the end of the quarter.

Standard Oil of Indiana's 5% earnings decline was largely attributable to poorer results for U.S. refining, marketing, and transportation operations, which suffered from severely depressed margins as a result of competitive gasoline market conditions.

Lower crude oil prices and sales volumes in petroleum exploration and production operations and lower margins in refining and marketing operations contributed to Standard Oil of Ohio's 39% drop in net income.

The combined effect of surplus supplies of crude oil, excess manufacturing capacity, and unneeded marine tonnage had a depressing impact on the gross operating margins for Texaco's manufacturing and marketing operations. Net income declined 13%.

American Petrofina's 98% drop in net earnings was primarily due to losses in the refining and marketing segment, where severe competition during the first two months of the quarter held prices below costs.

Anglo Energy posted a $12 million loss for the quarter due to reduced spending for exploration and production of oil and gas by major and independent oil companies in reaction in part to lower oil prices and gas oversupplies.

Ashland Oil also reported a net loss amounting to $14.5 million. The economic recession and petroleum market instability was blamed.

A net loss was reported by Beard Oil, totaling $352,000. Operating revenues were adversely affected by a decline in oil and gas sales due to lower oil prices and production and a decline in drilling and well servicing revenues.

Belco Petroleum posted a 3% increase in net income as a result of higher oil and gas production and prices in Canada and higher gas prices in the U.S.

Recent softness in oil and gas prices and the continued slowdown of industry-wide activities took its toll at Callon Petroleum. Earnings dropped 99%.

Despite increased revenues from expanded marketing activities, net income at Dorchester Gas de-

OIL COMPANIES' FIRST QUARTER FINANCIAL REPORTS

	Three months ending March 31**							
	Revenues ($000)			Earnings* ($000)			Profit Margin‡	
Company	1983	1982	% Chg.	1983	1982	% Chg.	1983	1982
Adobe Oil & Gas Corp.	41,703	53,864	- 22.6	5,671	5,901	- 3.9	13.6	11.0
Altex Oil	892	1,671	- 46.6	(319)	(30)			
Amerada Hess	1,844,206	2,373,216	- 22.3	4,988	(16,164)		0.3	
American Pacific	4,849	2,929	+ 65.6	(361)	(777)			
American Petrofina	425,339	575,214	- 26.1	336	15,995	- 97.9	0.1	2.8
American Quasar	11,552	14,815	- 22.0	(585)	1,959			13.2
Anglo Energy	62,147	93,748	- 33.7	(12,055)	2,109			2.3
Arapaho Petroleum	1,324	1,519	- 12.8	(264)	(222)			
Argo Petroleum	5,226	5,692	- 8.2	(725)	(593)			
Ashland Oil	1,814,065	2,213,666	- 18.1	(23,592)	(20,868)			
Asamera	88,882	113,465	- 21.7	(5,653)	(690)			
Atlantic Richfield	6,364,360	6,534,489	- 2.6	330,379	385,409	- 14.3	5.2	5.9
Beard Oil	8,354	9,109	- 8.3	(352)	429			4.7
Belco Petroleum	76,145	81,630	- 6.7	27,467	26,728	+ 2.8	36.1	32.7
Buttes Gas & Oil	32,244	54,125	- 40.0	1,127	2,062	- 45.0	3.5	3.8
Callon Petroleum[1]	6,163	4,804	+ 28.3	4	680	- 99.4	0.1	14.2
Commonwealth Oil Ref.	10,900	164,200	- 93.3	(3,000)	(18,000)			
Consolidated O&G[1]	9,510	11,535	- 17.6	(1,178)	(2,172)			
Crown Central	347,433	413,604	- 16.0	(10,833)	(3,367)			
Crystal Oil	49,032	61,027	- 19.7	(355)	(783)			
Damson Oil	20,896	16,263	+ 28.5	2,255	1,491	+ 51.2	10.8	9.2
Diamond Shamrock	855,433	791,135	+ 8.1	4,634	29,149	- 84.1	0.5	3.7
Discovery Oil	1,620	967	+ 67.5	(484)	(235)			
Dorchester Gas[1]	417,050	201,007	+107.5	2,589	3,988	- 35.1	0.6	1.9
Dyco Petroleum	12,740	14,287	- 10.8	2,372	3,950	- 39.9	18.6	27.7
Energy Reserves Group	38,421	42,247	- 9.1	3,546	573	+518.8	9.2	1.4
Enstar Corp.	93,815	95,074	- 1.3	11,229	10,541	+ 6.5	12.0	11.1
Equity Oil	5,512	6,017	- 8.4	1,142	1,238	- 7.8	20.7	20.6
Exeter Oil	1,096	1,071	+ 2.3	105	156	- 32.7	9.6	14.6
Exxon	23,705,000	26,841,000	- 11.7	1,060,000	839,000	+ 26.3	4.5	3.1
Felmont Oil Corp.	21,454	18,028	+ 19.0	4,244	2,865	+ 48.1	19.8	15.9
Forest Oil Corp.	36,904	39,069	- 5.5	4,028	3,425	+ 17.6	10.9	8.8
Freeport McMoRan	204,215	194,875	+ 4.8	21,114	26,536	- 20.4	10.3	13.6
Galaxy Oil	3,243	3,340	- 2.9	(346)	(564)			
Getty Oil	3,005,091	3,140,090	- 4.3	157,844	179,740	- 12.2	5.3	5.7
Gulf Energy & Dev.	30,014	15,374	+ 95.2	1,256	435	+188.7	4.2	2.8
Gulf Oil Corp.	6,898,000	7,535,000	- 8.5	182,000	288,000	- 36.8	2.6	3.8
Hadson Petroleum	4,714	10,555	- 55.3	1,034	5,180	- 80.0	21.9	49.1
Hamilton Bros. Petroleum	45,564	54,155	- 15.9	3,398	5,911	- 42.5	7.5	10.9
Helmerich & Payne	61,872	94,762	- 34.7	10,923	20,418	- 46.5	17.7	21.5
Hershey Oil	1,781	1,786	- 0.3	273	225	+ 21.3	15.3	12.6
Howell Corp.	40,590	66,838	- 39.3	105	794	- 86.8	0.3	1.2
Howell Petroleum	22,321	22,814	- 2.2	2,494	2,042	+ 22.1	11.2	9.0
Inexco Oil	42,568	62,827	- 32.2	2,693	7,607	- 64.6	6.3	12.1
KRM Petroleum	1,095	1,370	- 20.1	13	130	- 90.0	1.2	9.5
Lear Petroleum	54,105	54,706	- 1.1	4,607	1,765	+161.0	8.5	3.2
Louisiana L&E	253,277	304,297	- 16.8	26,630	13,452	+ 98.0	10.5	4.4
Mapco Inc	469,436	480,836	- 2.4	13,370	16,013	- 16.5	2.8	3.3
May Petroleum	8,709	7,519	+ 15.8	(649)	663			8.8
Maynard Oil	8,865	11,338	- 21.8	(261)	1,015			9.0
MCO Holdings Inc.	39,937	43,731	- 8.7	2,391	4,206	- 43.1	6.0	9.6
McFarland Energy	3,774	3,759	+ 0.4	988	986	+ 0.2	26.2	26.2
Mesa Petroleum	106,715	104,139	+ 2.5	37,836	29,604	+ 27.8	35.5	28.4
Mitchell Energy[2]	240,462	231,137	+ 4.0	19,187	16,313	+ 17.6	8.0	7.1
Mobil Corp.	14,288,000	16,439,000	- 13.1	250,000	369,000	- 32.2	1.8	2.2
Moran Energy	23,379	29,059	- 19.5	1,386	4,083	- 66.0	5.9	14.1
Murphy Oil	711,009	744,355	- 4.5	27,871	33,378	- 16.5	3.9	4.5
Natomas	366,557	389,629	- 5.9	(6,551)	49,854			12.8
Noble Affiliates	77,555	114,688	- 32.4	7,083	22,438	- 68.4	9.1	19.6
Norris Oil	716	675	+ 6.1	39	172	- 77.3	5.4	25.5
Nugget Oil Corp.[3]	1,652	2,568	- 32.2	(280)	258			10.0
Occidental Petroleum	4,890,000	4,211,700	+ 16.1	25,900	62,100	- 58.3	0.5	1.5
Oxoco	11,675	7,501	+ 55.6	2,040	1,691	+ 20.6	17.5	22.5
Pacific Resources	269,513	284,042	- 5.1	(4,732)	(1,747)			
Pennzoil Co.	559,816	587,176	- 4.7	40,318	38,951	+ 3.5	7.2	6.6
Petroleum Development	5,327	2,228	+139.1	308	(336)		5.8	
Petro-Lewis	100,523	57,664	+ 74.3	9,950	1,883	+428.4	9.9	3.3
Prairie Producing Co.	4,637	7,130	- 35.0	590	1,416	- 58.3	12.7	19.9
Phillips Petroleum	3,637,000	3,805,000	- 4.4	129,000	192,000	- 32.5	3.6	5.0
Presidio Oil	1,590	2,216	- 28.2	83	286	- 71.0	5.2	12.9
Quaker State	213,227	224,012	- 4.8	6,157	5,824	+ 5.7	2.9	2.6
Sabine Corp.	32,574	47,880	- 32.0	3,800	5,726	- 32.2	11.9	12.0
Seneca Oil	5,120	5,512	- 7.1	(1,323)	(593)			
Shell Oil	4,645,000	4,842,000	- 4.1	246,000	345,000	- 28.7	5.3	7.1
Southland Royalty	82,428	94,838	- 13.0	8,741	8,596	+ 1.7	10.6	9.1
Southwestern Energy	26,177	21,011	+ 24.6	5,449	4,220	+ 29.1	20.8	20.1
Standard California	6,995,000	10,020,000	- 30.2	310,000	230,000	+ 35.0	4.4	2.3
Standard Indiana	7,500,000	7,200,000	+ 4.2	399,000	470,000	- 5.1	5.3	6.5
Standard Ohio	2,766,000	3,617,000	- 23.5	277,000	455,000	- 39.1	10.0	12.6
Statex Petroleum[3]	3,003	3,368	- 10.8	(72)	581	+113.7	2.4	17.2
Sun Co.	3,740,000	4,060,000	- 7.9	90,000	124,000	- 27.4	2.4	3.1
Sundance Oil	22,646	23,364	- 3.1	2,078	(2,810)		9.2	
Superior Oil	457,563	530,684	- 13.8	23,698	83,378	- 71.6	5.2	15.7
Tenneco	3,609,000	3,766,000	- 4.2	111,000	128,943	- 13.9	3.1	3.4
Tesoro	515,138	606,346	- 15.0	4,134	3,765	+ 9.8	0.8	0.6
Texaco Inc.	10,148,000	12,986,000	- 21.9	319,000	367,000	- 13.1	3.1	2.8
Texas American	73,467	69,713	+ 5.4	2,582	2,002	+ 28.9	3.5	2.9
Texas International	34,976	44,777	- 21.9	238	2,977	- 92.0	0.7	6.7
Tosco Corp.	725,115	823,011	- 11.9	(46,603)	510			0.1
Total Petroleum N.A.	501,164	544,387	- 7.9	(37,096)	4,596			0.8
Tribune Oil	769	569	+ 35.2	314	182	+ 72.5	40.8	32.0
Union California	2,474,000	2,481,600	- 0.3	128,300	168,500	- 23.9	5.2	6.8
Universal Resources	12,578	17,086	- 26.4	(623)	3,008			17.6
Wainoco Oil	12,910	13,598	- 5.1	1,059	(2,746)		8.2	
Westcoast Petroleum	14,018	11,420	+ 22.7	3,608	2,992	+ 20.6	25.7	26.2
Wilshire Oil of Texas	2,812	3,027	- 7.1	747	279	+167.7	26.6	9.2
Wiser Oil	14,990	14,750	+ 1.6	3,960	3,642	+ 8.7	26.4	24.7
Woods Petroleum	18,480	20,332	- 9.1	4,710	5,767	- 18.3	25.5	28.4
Worldwide Energy	17,619	14,145	+ 24.6	1,381	(144)		7.8	
TOTAL	117,573,338	132,086,797	- 11.0	4,243,504	5,089,840	- 16.6	3.6	3.9

*Earnings available to common. **Excluding non-recurring items. ( ) Loss. ‡Earnings* divided by revenues. [1] Ends February 28. [2] Ends April 30. [3] Ends January 31.

creased 35% due to lower gas takes resulting from the current oversupply of natural gas as well as continued weakness in coal markets and in contract drilling.

Improved results from gas transmission and distribution operations in Alaska and $4.1 million realized after taxes from the sale of a coal-producing property in Texas contributed to Enstar's 6.5% increase in earnings.

Gulf Energy & Development reported a 189% increase in net income due to increased gas throughput, increased natural gas liquid products sales, and higher natural gas liquid sales prices.

The 42.5% decline in earnings at Hamilton Brothers Petroleum was a result of decreased income from gas transportation systems, resulting from the current weak demand for natural gas.

Howell Corp. posted an 87% drop in earnings due to the continued weakness of conventional fuel products markets.

Louisiana Land & Exploration's net income increased 98% as a result of a decrease in dry holes and exploration charges and reduced overhead expenditures.

Losses sustained by onshore contract drilling operations were primarily responsible for the 66% drop in earnings at Moran Energy.

Natomas reported a $6.6 million loss for the first quarter due mainly to a loss by their transportation subsidiary, increased interest expense, and reduced prices for international petroleum production.

Superior Oil's 72% drop in earnings was due to lower world crude oil prices, unusually warm weather, and the recession's lingering impact on oil and gas demand.

Declines in exploration and production and refining and marketing resulted in a 14% drop in net income at Tenneco.

Texas International's net earnings dropped from $3 million in 1982 to $238,000 in the first quarter of 1983.

The 27 gas companies responding to our survey reported a 15% drop in net earnings in the first quarter. Profit margin fell from 5.2% to 4.4%.

The warm winter drove American Natural Resources' net income down 24% from the first quarter of 1982.

Coastal Corp. reported a 135% increase in earnings. Most of the improvement came from natural gas pipeline operations.

Consolidated Natural Gas Co. posted a 20% decline in net earnings due to the warmest weather in 30 years.

Successful oil and gas development drilling by Mountain Fuel subsidiaries contributed to the 18% increase in net income.

The main reasons for Pacific Lighting's 12% increase in earnings were better results of utility and energy-related operations.

Peoples Energy reported a 16% drop in net income due to increasing losses of large-volume commercial and industrial business to No. 6 oil, the low level of economic activity in the Chicago area, customer conservation, and unsatisfactory rate orders.

Lower prices and production volumes for North Sea oil, as well as combined effects of continued U.S. recession and mild winter weather resulted in a 39% drop in earnings at Texas Eastern.

United Energy Resources reported a drop of 38% in net earnings due to the economic recession, low alternate fuel prices, and the excess supply of natural gas. ■

FINANCIAL NOTEBOOK

Capital appropriations by the nation's 1,000 largest manufacturers remained virtually unchanged at $21 billion (seasonally adjusted) in the first quarter, according to The Conference Board.

The petroleum industry, whose appropriations are both volatile and large, increased its appropriations 17.3% during the quarter while other manufacturing industries recorded an 8% decline overall.

The Conference Board reports the current outlook is for capital appropriations to rise only 6% this year. Excluding petroleum, appropriations are expected to be up only 1%.

Mergers/acquisitions. Coquina Oil (Midland, Tex.), formerly a Fluor unit, was acquired by American National Petroleum (Houston, Tex.).

Meenan Oil agreed to sell the operating assets of its Blueray Systems unit to a Vari Corp. subsidiary.

Noarko Resources (Denver, Colo.) and Aztec Energy (Farmington, N. M.) agreed to merge.

Hamilton Brothers Petroleum agreed to sell its entire equity position in Gulf Energy & Development to The Penn Central Corp. for $22.3 million.

Canadian Occidental Petroleum will acquire Canada-Cities Service for $362.5 million (Canadian).

Terrapet Energy (Dallas, Tex.) withdrew from negotiations concerning the acquisition of Teton Energy (Denver, Colo.).

Diamond Shamrock plans to acquire up to 30.4 million common shares of Natomas Co. (San Francisco, Calif.). The company also intends to propose a merger of the two companies.

Properties acquired. United States Oil plans to purchase a block of Federal oil/gas leases covering about 54,500 acres in Montana.

Western Energy Development sold a 16.45% working interest in 11 producing wells and 507 surrounding acres in Runnels County, Tex. to Northstar Energy for $2.5 million.

Money Markets. Beard Oil plans to close on the sale of $10 million of its 12%, 15-year senior notes to an institutional investor. Proceeds will be used to repay a bank debt.

Saber Energy (Houston, Tex.) secured a $250 million working capital line of credit.

MGF Oil refinanced its existing secured bank debt for 2 years.

Contracts. Aramco awarded 2 engineering construction contracts for work in the Marjan Field off Saudi Arabia to Brown & Root.

National Supply's well control systems division was awarded a multi-million dollar contract from Union Oil of Thailand for the production of offshore platform wellhead equipment.

Briefs. Texas Gas Corp. changed their name to Texas Gas Resources Corp.

Foster Wheeler Corp. formed a new unit called Foster Wheeler Energy Resources. ■